The Duke Energy Carolinas Integrated Resource Plan (Annual Report)

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TABLE OF CONTENTS

Integrated Resource Plan – abbreviations

Carbon Dioxide	CO_2
Central Electric Power Cooperative, Inc.	CEPCI
Certificate of Public Convenience and Necessity	CPCN
Clean Air Interstate Rule	CAIR
Clean Air Mercury Rule	CAMR
Coal Combustion Residuals	CCR
Combined Construction and Operating License	COL
Combined Cycle	CC
Combustion Turbines	CTs
Commercial Operation Date	COD
Compact Fluorescent Light bulbs	CFL
Cross State Air Pollution Rule	CSAPR
Demand Side Management	DSM
Direct Current	DC
Duke Energy Annual Plan	The Plan
Duke Energy Carolinas	DEC
Duke Energy Carolinas	The Company
Eastern Interconnection Planning Collaborative	EIPC
Electric Membership Corporation	EMC
Electric Power Research Institute	EPRI
Energy Efficiency	EE
Environmental Protection Agency	EPA
Federal Energy Regulatory Commission	FERC
Federal Loan Guarantee	FLG
Flue Gas Desulphurization	FGD
General Electric	GE
Greenhouse Gas	GHG
Heating, Ventilation and Air Conditioning	HVAC
Information Collection Request	ICR
Integrated Gasification Combined Cycle	IGCC
Integrated Resource Plan	IRP
Interruptible Service	IS
Load, Capacity, and Reserve Margin Table	LCR Table
Maximum Achievable Control Technology	MACT
Nantahala Power & Light	NP&L
National Ambient Air Quality Standards	NAAQS
National Pollutant Discharge Elimination System	NPDES
NC Department of Environment and Natural Resources	NCDENR
NC Green Power	NCGP
New Source Performance Standard	NSPS
Nitrogen Oxide	NO_x
North American Electric Reliability Corp	NERC
North Carolina	NC
North Carolina Clean Smokestacks Act	NCCSA
North Carolina Division of Air Quality	NCDAQ
North Carolina Electric Membership Corporation	NCEMC
North Carolina Municipal Power Agency #1	NCMPA1

Integrated Resource Plan – abbreviations

North Carolina Utilities Commission	NCUC
Notice of Proposed Rulemaking	NOPR
Nuclear Regulatory Commission	NRC
Palmetto Clean Energy	PaCE
Parts Per Billion	PPB
Photovoltaic	PV
Piedmont Municipal Power Agency	PMPA
Plug-In Electric Vehicles	PEV
Power Delivery	PD
Present Value Revenue Requirements	PVRR
Prevention of Significant Deterioration	PSD
Public Service Commission of South Carolina	PSCSC
Purchase Power Agreement	PPA
Qualifying Facility	QF
Rate Impact Measure	RIM
Renewable Energy and Energy Efficiency Portfolio Standard	REPS
Renewable Energy Certificates	REC
Renewable Portfolio Standard	RPS
Request for Proposal	RFP
Resource Conservation Recovery Act	RCRA
Saluda River Electric Cooperative	SR
Selective Catalytic Reduction	SCR
SERC Reliability Corporation	SERC
South Carolina	SC
Southeastern Power Administration	SEPA
Standby Generation	SG
State Implementation Plan	SIP
Sulfur Dioxide	SO_2
Technology Assessment Guide	TAG
Total Resource Cost	TRC
United States Department of Energy	USDOE
Utility Cost Test	UCT
Virginia/Carolinas	VACAR
Volt Ampere Reactive	VAR
Western Carolina University	WCU

FOREWARD

This Integrated Resource Plan (IRP) is the third biennial report filed by Duke Energy Carolinas, LLC (Duke Energy Carolinas or the Company) under the revised Commission Rule R8-60. A cross reference identifying the location of each regulatory requirement within this IRP is provided in Appendix L.

Due to the timing of the Duke Energy Corporation and Progress Energy Corporation merger closing, Duke Energy Carolinas and Progress Energy Carolinas, Inc. (PEC) were not able to coordinate their respective 2012 IRP filings. Input assumptions such as fuel prices, environmental inputs, and generation costs, as well as sensitivities and scenarios were developed independently. Assumptions around key inputs such as Energy Efficiency (EE), Demand Side Management (DSM), renewable resources and carbon dioxide (CO_2) regulation costs will be reconciled in the next planning cycle. Neither Duke Energy Carolinas nor PEC has included any consideration of joint planning of new build capacity or the sharing of existing capacity between the operating companies for the purposes of meeting this capacity need in their respective 2012 IRPs.

Post-merger review of the Duke Energy Carolinas and PEC 2012 IRP results indicate common themes, such as the inclusion of additional natural gas generation, the viability of regional nuclear projects to meet future capacity needs, and the commitment to meet the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS) requirements.

The North Carolina Utilities Commission (NCUC) issued three orders since the filing of the 2011 Duke Energy Carolinas IRP that require Duke Energy Carolinas to address certain new requirements in the 2012 IRP. An outline of the three orders and specific requirements are shown below.

Pursuant to its October 26, 2011 *Order Approving 2010 Biennial Integrated Resource Plans and 2010 REPS Compliance Plans*, the NCUC set forth new requirements listed below:

- Duke Energy Carolinas and PEC should each prepare a comprehensive reserve margin requirements study and include the results of such study as part of their 2012 biennial IRPs;
- Each IOU and EMC should investigate the value of activating DSM resources during times of high system load as a means of achieving lower fuel costs by not having to dispatch peaking units with their associated higher fuel costs if it is less expensive to activate DSM resources; and
- Each electric utility should use appropriately updated DSM/EE market potential studies.

Pursuant to its May 30, 2012 *Order Approving 2011 Annual Updates to the 2010 Biennial Integrated Resource Plan and 2011 REPS Compliance Plans*, the NCUC set forth new requirements listed below.

- Each IOU shall include a discussion of variance of 10% or more in projected Energy Efficiency savings from one IRP report to the next; and
- Each IOU shall include a discussion of the status of market potential studies or updates in their 2012 and future IRPs.

Finally, pursuant to its April 11, 2012 *Order Amending Commission Rule R8-60 and Adopting Commission Rule R8-60.1* in the Matter of Integrated Resource Planning in North Carolina addressing Smart Grid Technology Plans, the NCUC set forth the requirements listed below.

- Smart Grid Impacts – Each utility shall provide information regarding the impacts of its smart grid deployment plan on the overall IRP.
- The Smart Grid Technology Plan – By July 1, 2013 and every two years thereafter, each utility subject to Rule R8-60 shall file with the Commission its smart grid technology plan. Significant amendments or revisions to a smart grid technology plan shall be reported to the commission in each year in which the biennial smart grid technology plan is not required to be filed.

Each of these requirements is addressed the Company's IRP.

1. EXECUTIVE SUMMARY

Duke Energy Carolinas, a subsidiary of Duke Energy Corporation, utilizes an integrated resource planning approach to ensure that it can reliably and economically meet the electric energy needs of its customers well into the future. Duke Energy Carolinas considers a diverse range of resources to meet such future energy needs including renewable, nuclear, coal, gas, EE, and DSM[1] resources.

Consistent with its responsibility to meet customer energy needs in a way that is affordable, reliable, and clean, the Company's resource planning approach includes both quantitative analysis and qualitative considerations. Quantitative analysis provides insights on future risks and uncertainties associated with fuel prices, load growth rates, capital and operating costs, and other variables. Qualitative perspectives, such as the importance of fuel diversity, the Company's environmental profile, the emergence and development of new technologies, and regional economic development considerations are also important factors to consider as the Company makes long-term decisions regarding new resources to serve its customers.

Company management utilizes all of these qualitative perspectives in conjunction with its quantitative analyses to ensure that Duke Energy Carolinas will meet near-term and long-term customer needs, while maintaining the operational flexibility to adjust to evolving economic, environmental, and operating circumstances in the future. As a result, the Company's plan is designed to be robust under many possible future scenarios.

Changes from the 2011 IRP

The notable changes from the 2011 IRP to the 2012 IRP are (1) a shift in the Company's first capacity need from 2015 to 2016 and (2) lower projected fundamental natural gas prices throughout the planning horizon.

The shift of the Duke Energy Carolinas' first capacity need from 2015 to 2016 is primarily due to lower forecasted load projections, an increase in projected capacity and energy purchases from qualifying facilities (QF) pursuant to the requirements of the Public Utility Regulatory Policy Act of 1978 (PURPA), an increase in projected participation in DSM programs, a lower planning reserve margin, as well as changes in the Company's projected compliance portfolio relating to the NC REPS. These factors, taken together, result in the Company's first new resource need of 410 MWs in 2016. Each of these contributing factors is discussed in greater detail below:

[1] Throughout this IRP, the term EE will denote conservation programs while the term DSM will denote Demand Response programs, consistent with the language of N.C. Gen. Stat. 62-133.8 and 133.9.

- **Lower Forecasted Load Projection** - Short term lower load growth projections in the residential and commercial sectors and long term increases in EE projections are driving the lower forecasted Company load projections.

- **Increase in Projected QFs** - The increase in projected QF capacity and energy arises from the potential addition of new solar QF facilities and due to the renewal of the 88 MW Cherokee Co-Generation QF contract. The Cherokee contract was due to expire in 2013, but has now been extended through 2020. The increase in projected solar QF facilities not only affects the capacity need, but also impacts the Company's NC REPS compliance strategy.

- **Increase in the Projected DSM Implementation** - The Company is also projecting additional DSM implementation in the 2012 IRP because the final Environmental Protection Agency (EPA) Reciprocating Internal Combustion Engine (RICE) rule, which limits hours of non-emergency operation of emergency generators located at commercial and industrial facilities, was not as stringent as the original proposed rule from 2011. Also, the projected impacts of Distribution Automation, which provides the ability to reduce line voltage during periods of peak demand, have been incorporated in the DSM program. Distribution Automation is a part of the Duke Energy Carolinas Grid Modernization program. The projected increases in DSM impacts result in a corresponding 60 MW decrease in our customers' capacity needs by 2015.

- **Increase in the Projected Renewables** - The Company's analysis reflects a shift in strategy for NC REPS compliance over the long term. In the 2011 IRP, the NC REPS compliance strategy relied primarily on wind and biomass resources during the first 10 years and a shift to primarily biomass resources for the remainder of the planning period. Based upon the increase in recent proposals for solar QF facilities, for the 2012 IRP, the Company's strategy has shifted from a reliance on biomass to a greater reliance on solar resources. Even though solar facilities have a lower contribution to the Company's peak than biomass resources, the projected increase in volume of solar QFs results in a net increase of renewable resources available to meet peak demand requirements in 2015 of approximately 40 MWs.

- **Lower Planning Reserve Margin** - As part of the NCUC's approval of the utilities' respective 2010 IRPs, Duke Energy Carolinas and PEC were ordered to perform a quantitative analysis of the respective reserve margins and to provide the study results in the companies' 2012 IRPs. Based on the results of this analysis, Duke Energy Carolinas utilized a target Planning Reserve margin of 15.5% in the 2012

IRP. This is a reduction from a 17% target Planning Reserve margin used in the 2011 IRP, which resulted in approximately 200 MWs of reduced capacity need in 2015.

The second major change from the 2011 IRP to the 2012 IRP is that anticipated lower natural gas prices drove the selection of additional combined cycle generation rather than additional combustion turbine generation throughout the 20-year planning period. For example, the 2012 IRP found that the 2016 resource need would be served most cost-effectively by combined cycle resources instead of by the combustion turbine resources identified in the 2011 IRP.

Other important factors impacting the 2012 IRP:

As outlined below, a number of additional environmental and economic factors influence the Company's long-term resource plan.

- **Greenhouse Gas Regulation or Legislation** - Greenhouse gas (GHG) regulations or legislation also have the potential to impact the Company's resource planning. From 2007 to 2009, multiple GHG cap and trade bills were introduced in Congress. More recently, Clean Energy Standards (CES) have been discussed in lieu of cap and trade legislation or regulation. A CES would require that a certain percentage (e.g. 10% in 2015 escalating up to 30% in 2030) of a utility's retail sales be met with combined cycle (CC) natural gas, nuclear, EE, or renewable energy. At present, the Company does not anticipate that Congress will consider GHG legislation before the end of 2012. Beyond 2012, the prospects for possible enactment of any legislation mandating reductions in GHG emissions are highly uncertain. Although the Company continues to believe that Congress will eventually adopt some form of mandatory GHG emission reduction or Clean Energy legislation, the timing and form of any such legislation remains highly uncertain.

- **EPA GHG Regulation** - In the absence of federal GHG or Clean Energy legislation, the EPA continues to pursue GHG regulations on new and existing units. In 2011, EPA promulgated its Tailoring Rule for existing fossil-fired generating units which sets the emission thresholds to 75,000 tons/year of CO_2 for determining when a source is potentially subject to Prevention of Significant Deterioration (PSD) permitting for GHGs. Also in 2012, the EPA proposed a rule to establish GHG new source performance standards (NSPS) for new pulverized coal and natural gas units. If finalized as proposed, the GHG NSPS would effectively preclude construction of new pulverized coal units because the standards were set at a level requiring carbon capture and storage (CCS) technology. New natural gas combined cycle facilities will be able to meet the proposed standard without CCS technology. The future impacts of these EPA regulations are uncertain at this time, and there are presently no cost-effective and demonstrated controls for CO_2 for new or existing fossil units. Due to the EPA's continued pursuit of GHG regulation in absence of GHG legislation, the Company believes that it is prudent to continue to plan for a carbon-constrained future. To address this uncertainty, the Company has evaluated a range of CO_2 prices, in addition to potential Clean Energy legislation.

- **Impact of Lower Natural Gas Prices** - Despite the lower projected natural gas prices, on a long-term basis, Duke Energy Carolinas' analysis continues to support a robust portfolio including new nuclear, CC, and CT generation resources. Thus, in the 2012 IRP, portfolios consisting of new nuclear and gas generation remain competitive with portfolios where all intermediate and base load needs are met with natural gas resources. Without new nuclear generation, CO_2 emissions for the natural gas portfolio are projected to continue to rise throughout the planning period. In addition, the Company's fundamental natural gas prices were developed assuming continued operation of the nation's existing nuclear fleet. The operating licenses of many of the country's existing nuclear units have already been extended and will expire within the planning horizon. If these units are replaced with natural gas resources, the result would be a projected increase in natural gas prices, which would impact the cost-effectiveness of both future natural gas and new nuclear generation. As discussed above, although GHG legislation is not believed to be imminent, the EPA continues to pursue CO_2 regulations on existing and new generation units, which will also impact the future cost for any CO_2-emitting generation. For these reasons, among others, the Company believes it is prudent to continue to preserve the option for new nuclear generation in combination with new CC and CT resources.

Overview of Planning Process Results

Duke Energy Carolinas' generation resource needs increase significantly over the 20-year planning horizon of the 2012 IRP. Cliffside Unit 6, the Buck and Dan River natural gas CC units, the potential conversion of Lee Steam Station Unit 3 to natural gas fuel, along with the energy and capacity savings achievements of the Company's EE and DSM programs, will fulfill these needs through 2015. Beginning in 2016, the Company has a capacity need of 410 MWs to meet its projected capacity requirements including a 15.5% reserve margin. Even if the Company fully realizes its goals for EE and DSM, the resource need grows to approximately 6,360 MWs by 2032.

The 2012 Duke Energy Carolinas IRP outlines the Company's options and plans for meeting its projected long-term needs. The general factors that influence the Company's future resource needs are:

- Future load growth projections;
- The amount of EE and DSM that can be achieved;
- Resources needed to meet the NC REPS requirement;
- Reductions in existing resources, for example, due to unit retirements and expiration of purchased power agreements (PPA); and
- Meeting the Company's 15.5% target planning reserve margin over the 20-year horizon.

A key purpose of the IRP is to provide the Company's management with information to aid in making the decisions necessary to ensure that Duke Energy Carolinas has a reliable, diverse, environmentally sound, and reasonably priced portfolio of resources over time.

Both DSM and EE programs play important roles in the Company's development of a balanced, cost-effective and environmentally responsible resource portfolio. Renewable generation options are also necessary to meet the NC REPS enacted in 2007. These resources will be incorporated more broadly into the Company's resource portfolio to the extent they become more cost-effective in comparison with traditional supply-side resources and with consideration of other qualitative issues such as their intermittency and relative contribution to meeting peak capacity needs. Energy savings resulting from EE programs may also be used to meet, in part, the Company's REPS obligations. The Company's REPS Compliance Plan is being filed concurrently with the 2012 IRP, pursuant to the requirements of NCUC Rule R8-67.

In the short term, Duke Energy Carolinas' 2012 IRP analysis results indicate the need for intermediate to base load resources in 2016 and 2018 and at various points throughout the study period in addition to significant EE, DSM, and renewable resources. The Company identified combined cycle generation as the optimal resource to meet its 2016 and 2018 capacity needs.

For Duke Energy Carolinas' longer term need, the Company's analysis continues to affirm the potential benefits of new nuclear capacity in a carbon-constrained future. The Company's analysis considered a portfolio based on full ownership of the 2,234 MW Lee Nuclear Station by the summer of 2022 and 2024, as well as a portfolio that reflects regional nuclear generation equivalent to the MWs associated with Lee Nuclear Station distributed over 2017 to 2028. Regional nuclear is where two or more partners plan collaboratively to stage multiple nuclear stations over a period of years and each partner would own a portion of each station. The regional nuclear portfolio is illustrative of the potential value to customers of a representative regional nuclear generation plan. Duke Energy Carolinas continues to strongly support regional nuclear opportunities and is actively pursuing this concept. As the Company announced in 2011, Duke Energy Carolinas has agreements with JEA, located in Jacksonville, Florida, and with the Public Service Authority of South Carolina (Santee Cooper). Duke Energy Carolinas has an agreement with Santee Cooper to perform due diligence and potentially acquire an option for a minority interest (5 to 10% of the capacity of the two units) in Santee Cooper's 45% ownership of the planned new nuclear reactors at V.C. Summer Nuclear Generating Station in South Carolina. The new Summer units are scheduled to be online in 2017 and 2018. JEA has signed an option agreement to potentially purchase up to 20% of Lee Nuclear Station.

The Company's analysis indicates that the regional nuclear portfolio is lower cost to customers in the base case and in most scenarios. However, the full nuclear portfolio was chosen for the 2012 IRP preferred plan because there are no firm commitments in place at this time for the regional nuclear portfolio. Although the regional nuclear portfolio assumes 10% of the Summer station is purchased, the Company's decision on whether and how much to purchase will be based on many factors, including the results of the due diligence related to Summer, the capacity need at the time of the decision, and the financial implications of the purchase on the Company. Duke Energy Carolinas will continue to assess opportunities to benefit from economies of scale and risk reduction in new resource decisions by considering the prospects for joint ownership and/or sales agreements for new nuclear generation resources.

The 2012 IRP also includes the Company's plan for meeting the requirements set forth in the Cliffside Unit 6 NCDAQ Air Permit (Cliffside Air Permit). The Cliffside Air Permit requires that the Company take specific actions to render Cliffside Unit 6 carbon neutral by 2018. In its order approving the utilities' respective 2011 IRPs, the NCUC approved the Company's proposed carbon neutrality plan as required by the Cliffside Air Permit. The Company's plan has been updated in the 2012 IRP to reflect changes in energy efficiency projections, NC REPS compliance and other ongoing activities. With the incorporation of these updates, the Company's proposed plan remains robust by projecting to eliminate approximately 9.2M tons of CO_2, where the emission reduction requirement is approximately 5.3M tons to render Cliffside Unit 6 as carbon neutral by 2018.

Duke Energy Carolinas has developed a sustainable strategy to ensure that the Company can meet customers' energy needs reliably and economically over the near and long term. The strategic action plan for long-term resources maintains prudent flexibility in the face of uncertain and constantly evolving circumstances.

Short Term Action Plan

The Company's Short Term Action Plan, which identifies accomplishments in the past year and actions to be taken over the next five years, is summarized below:

- Take actions to ensure capacity needs beginning in 2016 are met. In addition to seeking to meet the Company's DSM and EE goals and meeting the Company's REPS requirements, actions to secure additional capacity may include purchased power or generating capacity or Company-owned generation.

- Continue to evaluate and plan for the retirement of older coal generation. Buck Steam Station Units 3 and 4 were retired in May 2011. Cliffside Units 1 through 4 and Dan River Units 1 and 2 were retired in October 2011 and April 2012, respectively, in advance of the initial testing of new generation at those locations. Retirements of the remaining un-scrubbed coal units at Buck, Riverbend and Lee Steam Stations are currently planned for April 2015 to correspond with the compliance requirements of the Mercury Air Toxic Rule. Duke Energy Carolinas is also planning to retire all of its older CTs in October 2012.

- Continue to execute the Company's EE and DSM plan, which includes a diverse portfolio of EE and DSM programs, and continue on-going collaborative work to develop and implement additional cost-effective EE and DSM products and services. Over the past year, PowerShare® impacts have increased, offsetting approximately 40 MW of peak capacity need and energy efficiency achievements have reduced energy consumption by over 560,000 MWh.

- Completed Bridgewater Hydro Station generating unit upgrades. The units were operational November 2011. The previous generating units were replaced by two 15 MW units and a small 1.5 MW unit representing an 8.5 MW increase in station capability. The new generating units will be used to meet continuous release requirements and system peak.

- Completed construction of the new Buck Combined Cycle (CC) unit. The unit was operational November 2011. The 620 MW natural gas-fired CC generating station achieves high operational flexibility and high thermal efficiency while utilizing state-of-the-art environmental control technology to minimize plant emissions.

- Complete construction of the 825 MW Cliffside Unit 6, at the existing Cliffside Steam Station. As of August 2012, the project is in testing phase with commercial operation expected in September 2012.
- Complete construction of the 620 MW combined-cycle plant at Dan River Steam

Station. As of August 2012, the project was over 90% complete.

- Continue to assess the conversion of Lee Steam Station Unit 3 from coal to natural gas fuel. Lee Steam Station Unit 3 is reflected in the 2012 Duke Energy Carolinas IRP as a retired coal unit in the fourth quarter of 2014 and converted to natural gas by January 1, 2015. Preliminary engineering has been completed and more detailed project development and regulatory efforts are ongoing.

- Continue to pursue the option for new nuclear generating capacity in the 2017 to 2028 timeframe.

  - The Company submitted an application for a Combined Construction and Operating license (COL) and an environmental report to the NRC on December 12, 2007. A supplement to the environmental report was filed September 24, 2009. The NRC issued its Draft Environmental Impact Statement for the William States Lee III Nuclear plant in December 2011, concluding that the NCUC's evaluation of Duke's future load demand and its accuracy in historical load forecasting within the 2011 IRP was a reasonable basis for planning.

  - The Company plans to continue to support the NRC evaluation of the COL. In March of 2012, the NRC issued a request for information letter to operating power reactor licensees regarding recommendations of the Near-Term Task Force review of insights from the Fukushima Dai-ichi accident. In April 2012, the NRC staff subsequently requested that Duke Energy update the W.S. Lee III (Lee) plant site-specific seismic analysis. This request impacted the schedule for NRC issuance of the Lee Combined Operating License, moving the projected Commercial Operation Date (COD) beyond the summer peak of 2021.

  - The Company continues to evaluate the optimal time to file the Certificate of Environmental Compatibility and Public Convenience and Necessity (CPCN) in South Carolina, as well as pursue other relevant regulatory approvals.

  - The Company will continue to pursue available federal, state and local tax incentives and favorable financing options at the federal and state level.

  - The Company will continue to assess opportunities to benefit from economies of scale and risk reduction in new resource decisions by considering the prospects for joint ownership and/or sales agreements for new nuclear generation resources.

- Continue to evaluate market options for renewable generation and procure capacity, as appropriate. PPAs have been signed with developers of solar photovoltaic (PV), landfill gas, wind, and thermal resources. Additionally, renewable energy certificate (REC) purchase agreements have been executed for purchases of unbundled RECs from wind, solar PV, solar thermal and hydroelectric facilities.

- Continue to investigate the future environmental control requirements and resulting operational impacts associated with the Mercury MACT rule, the CCR rule, the CSAPR rule and the new Ozone NAAQS and SO_2.

- Continue to pursue existing and potential opportunities for wholesale power sales agreements within the Duke Energy Balancing Authority Area.

- Continue to monitor energy-related statutory and regulatory activities.

A summarization of the capacity resource changes for the reference plan in the 2012 IRP is shown in Table 1.A below. Capacity retirements and additions are presented as incremental values in the year in which the change is projected to occur. The values shown for renewable resources, DSM, and EE represent cumulative totals.

Table 1.A

Duke Energy Carolinas Integrated Resource Plan

Year	Retirements	Additions (1)	Renewable Resources (Cumulative Nameplate MW)			EE	DSM (3)
			Wind (2)	Solar (2)	Biomass		
2013		34 MW Nuc	0	56	10	62	875
2014		65 MW Nuc	100	135	20	117	960
2015	Lee 1-3 (370 MW) Riverbend 4-7 (454 MW) Buck 5-6 (256 MW)	12 MW Nuc 170 MW Lee 3 NG	100	253	30	181	1046
2016		700 MW CC	134	320	51	247	1097
2017			135	352	60	317	1139
2018		700 MW CC	135	398	68	384	1152
2019		800 MW CT	322	471	90	451	1166
2020			323	495	99	517	1179
2021			324	538	108	585	1193
2022		1117 MW Nuc	376	649	135	652	1199
2023			378	692	133	720	1206
2024		1117 MW Nuc	381	736	142	785	1206
2025			416	840	154	854	1206
2026			419	885	155	921	1206
2027			422	928	156	988	1206
2028		700 MW CC	430	946	163	1053	1206
2029			439	965	166	1123	1206
2030		800 MW CT	448	984	170	1190	1206
2031			457	1004	173	1257	1206
2032		150 MW CT	457	1004	173	1320	1206
Total MW	1080	6365	457	1004	173	1320	1206

(1) Includes 111 MW of nuclear uprates

(2) Capacity is shown in nameplate ratings. For planning purposes, wind presents a 15% contribution to peak and solar has a 40% contribution to peak.

(3) Includes 135 MW impact of grid modernization

2. SYSTEM OVERVIEW, OBJECTIVES, AND PROCESS

A. System Overview

Duke Energy Carolinas provides electric service to an approximately 24,000-square-mile service area in central and western North Carolina and western South Carolina. In addition to retail sales to approximately 2.43 million customers, Duke Energy Carolinas also sells wholesale electricity to incorporated municipalities and to public and private utilities.

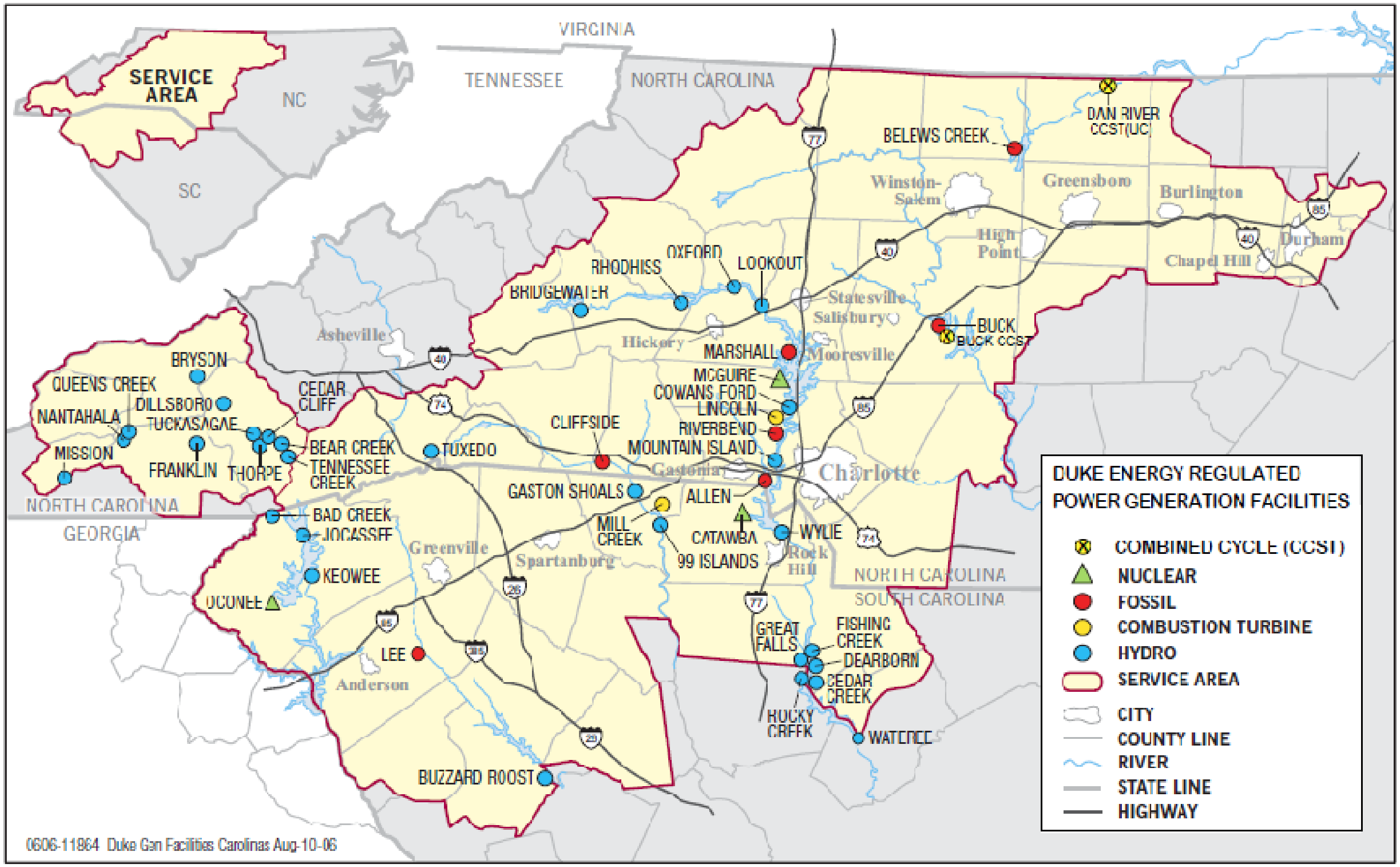
Duke Energy Carolinas currently meets energy demand, in part, by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- Three nuclear generating stations with a combined net capacity of 6,996 MW (including all of Catawba Nuclear Station);
- Seven coal-fired stations with a combined capacity of 7,057 MW;
- 29 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 3,229 MW; and
- Nine combustion turbine stations (including one Combined Cycle Station) with a combined capacity of 3,740 MW.

Duke Energy Carolinas' power delivery system consists of approximately 101,000 miles of distribution lines and 13,000 miles of transmission lines. The transmission system is directly connected to all of the utilities that surround the Duke Energy Carolinas service area. There are 36 circuits connecting with eight different utilities: Progress Energy Carolinas, American Electric Power, Tennessee Valley Authority, Southern Company, Yadkin, Southeastern Power Administration (SEPA), South Carolina Electric and Gas, and Santee Cooper. These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) sub-region, SERC Reliability Corporation (SERC) (formerly Southeastern Electric Reliability Council), and North American Electric Reliability Corporation (NERC).

The map on the following page provides a high-level view of the Duke Energy Carolinas system.

Duke Energy – Carolinas Service Area



B. Objectives

Duke Energy Carolinas has an obligation to provide reliable and economic electric service to its customers in North Carolina and South Carolina. To meet this obligation, the Company conducted an integrated resource planning process that serves as the basis for its 2012 IRP.

The purpose of this IRP is to outline a robust strategy to furnish electric energy services to Duke Energy Carolinas' customers in a reliable, efficient, economic, and increasingly clean manner while factoring in the uncertainty of the future.

The planning process itself must be dynamic and constantly adaptable to changing conditions. The IRP presented herein represents the most robust and cost effective outcome based upon the Company's analyses under various assumptions and sensitivities. Duke Energy Carolinas has performed sensitivity analyses as part of this IRP to account for the uncertainty of many factors influencing the business, including regulatory, economic, environmental and operational changes. Duke Energy Carolinas will continue to monitor these uncertainties and make adjustments as necessary and practical in future plans.

Duke Energy Carolinas' long-term planning objective is to employ a flexible planning process and pursue a resource strategy that considers the costs and benefits to all stakeholders (customers, shareholders, employees, suppliers, and community). At times, this involves striking a balance between competing objectives. The major objectives of the plan presented in this filing are:

- Provide adequate, reliable, and economic service to customers in an uncertain environment.
- Maintain the flexibility and ability to alter the plan in the future as circumstances change.
- Choose a near-term plan that is robust over a wide variety of possible futures.
- Minimize risks with the development of a balanced portfolio.

C. Planning Process

The development of the IRP is a multi-step process covering the planning period of 2012-2032, involving the following key planning functions:

- Developing planning objectives and assumptions.

- Considering the impacts of anticipated or pending regulations or events on existing resources (environmental, renewables, etc.).
- Developing a regulatory construct to assess the impact of potential CO_2 or Energy Policy legislation. More details of this step may be found in Appendix A.
- Preparing the electric load forecast. More details of this step may be found in Chapter 3.
- Identifying EE and DSM options. More details concerning this step can be found in Chapter 4.
- Identifying and economically screening for the cost-effectiveness of supply-side resource options. More details concerning this step of the process can be found in Chapter 5.
- Integrating the energy efficiency, renewable, and supply-side options with the existing system and electric load forecast to develop potential resource portfolios to meet the desired reserve margin criteria. More details concerning this step of the process can be found in Chapter 8 and Appendix A.
- Performing detailed modeling of potential resource portfolios to determine the resource portfolio that exhibits the lowest cost (lowest net present value of costs) to customers over a wide range of alternative futures. More details concerning this step of the process can be found in Chapter 8 and Appendix A.
- Evaluating the ability of the selected resource portfolio to minimize price and reliability risks to customers. More details concerning this step of the process can be found in Chapter 8 and Appendix A.

The Company's analytical methodology for resource planning includes the incorporation of sensitivity analysis of variables representing the highest risk going forward, such as the load forecast, construction costs, fuel prices, EE, carbon prices and emerging policy.

3. ELECTRIC LOAD FORECAST

The following section provides details on the Load Forecast created in the spring of 2012.

Duke Energy Carolinas' retail sales have grown at an average annual compound rate of 0.5% from 1996 to 2011, non-weather adjusted. The following table shows historical and projected major customer class growth, at a compound annual rate. The historical periods are non-weather adjusted.

Table 3.A
Retail Load Growth (kWh sales)

Time Period	Total Retail	Residential	Commercial	Industrial Textile	Industrial Non-Textile
1996-2011	0.5%	1.9%	2.3%	-6.9%	-0.5%
1996-2006	0.8%	1.9%	2.9%	-6.7%	0.3%
2006-2011	0.1%	1.9%	1.2%	-7.2%	-2.2%
2011-2031*	1.4%	1.3%	1.9%	-0.9%	1.0%

*Growth rates from 2011-2031 are derived using weather adjusted values for 2011. This differs from the Forecast Book located in Appendix B, which uses actual 2011 values.

A significant decline in the Industrial Textile class was the key contributor to the Company's low load growth from 2006 to 2011. The recession in 2008-2009 also slowed the Commercial, Residential and Other Industrial classes. For example, over the last 5 years an average of approximately 22,000 new residential customers per year has been added to the Duke Energy Carolinas service area. Before the recession, however, the average growth was 30,000-35,000.

Duke Energy Carolinas' total retail load growth over the planning horizon, 2012-2032, is driven by projected steady increases in the Residential, Commercial and Other Industrial classes. Textiles, however, are projected to experience a slow decline over the forecast horizon.

Retail load growth summaries are shown in the Duke Energy Carolinas Spring 2012 Forecast book in Appendix B.

Table 3.B
Retail Customers (Thousands, Annual Average)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Residential	1,840	1,872	1,901	1,935	1,972	2,016	2,052	2,059	2,072	2,081
Commercial	300	307	313	319	325	331	334	333	334	336
Industrial	8	8	8	7	7	7	7	7	7	7
Other	11	11	12	13	13	13	14	14	14	14
Total	2,159	2,198	2,234	2,275	2,317	2,368	2,407	2,413	2,427	2,439

Table 3.C
Electricity Sales (GWh Sold - Years Ended December 31)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Residential	24,466	23,947	25,150	26,108	25,816	27,459	27,335	27,273	30,049	28,323
Commercial	24,242	24,355	25,204	25,679	26,030	27,433	27,288	26,977	27,968	27,593
Industrial	26,259	24,764	25,209	25,495	24,535	23,948	22,634	19,204	20,618	20,783
Other	271	270	269	269	271	278	284	287	287	287
Total Retail	75,238	73,336	75,833	77,550	76,653	79,118	77,541	73,741	78,922	76,985
Wholesale	1,530	1,448	1,542	1,580	1,694	2,454	3,525	3,788	5,166	4,866
Total System	76,769	74,784	77,374	79,130	78,347	81,572	81,066	77,528	84,088	81,851

Note: Wholesale sales will vary over time due to new contract agreements.

Wholesale Power Sales Commitments

Table 3.D on the following page contains information concerning Duke Energy Carolinas' wholesale contracts. The description 'Full' indicates that Duke Energy Carolinas provides all of the needs of the wholesale customer. 'Partial' refers to those customers where Duke only provides some of the customer's needs. 'Fixed' refers to a constant load shape. As a note, the values in Table 3.D are net of self-supplied generation.

Table 3.D			Wholesale Contracts									
			Commitment (MWs)									
Customer	**Product**	**Term**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Concord, NC	Partial	2009-2018	181	180	184	187	190	192	195	198	201	204
Dallas, NC	Partial	2009-2028	11	11	11	12	12	12	12	12	13	13
Due West, SC	Partial	2009-2018	3	3	3	3	3	3	3	3	3	3
Forest City, NC	Partial	2009-2028	15	15	15	15	16	16	16	17	17	17
Greenwood, SC	Full	2010-2018	54	54	55	56	57	58	59	60	61	62
Highlands, NC	Full	2010-2029	8	8	8	8	8	8	8	8	8	9
Kings Mountain, NC	Partial	2009-2018	19	19	20	20	20	21	21	21	22	22
Lockhart Power	Partial	2009-2018	54	54	55	56	57	57	58	59	60	61
Prosperity, SC	Partial	2009-2028	2	2	2	2	2	2	2	2	3	3
Western Carolina University	Full	2010-2021	6	6	6	6	6	6	6	6	6	6
Blue Ridge EMC	Full	2010-2031	224	227	230	234	238	242	246	250	254	258
Central EPC	Partial	2013-2030	0	123	250	383	521	664	812	919	937	955
Haywood EMC	Full	2009-2021	20	20	20	20	21	21	21	22	22	22
NCEMC	Fixed	2009-2038	72	72	72	72	72	72	72	72	72	72
Piedmont EMC	Full	2010-2031	90	91	92	94	95	97	98	100	101	103
PMPA*	Backstand	2014-2020	0	0	47	47	47	47	47	47	47	47
Rutherford EMC	Partial	2010-2031	161	193	197	212	216	221	226	230	235	240
NCEMC*	Backstand	1985-2043	95	95	116	116	116	116	116	116	116	116
FERC Mitigation**	Full	2012-2014	150	150	150	150						

Note: For Resource Planning purposes the contracts above are assumed to renew through the end of the planning horizon, which is 2032.

*Note: All backstand contracts represent the portion that Duke Energy Carolinas commitment.

**Note: FERC Mitigation Sale represents the summer peak MW - Sale begins July 3, 2012 and extends through February 28, 2015

The Company's Spring 2012 Forecast includes projections of the energy needs of new future customers and current existing customers in Duke Energy Carolinas territory. Certain wholesale customers have the option of obtaining all or a portion of their future energy requirements from other suppliers. Although this may reduce Duke Energy Carolinas' obligation to serve those customers, Duke Energy Carolinas assumes for planning purposes that the contracts displayed in Table 3.D will be extended through the duration of the forecast horizon.

Pursuant to NCUC Rule R8-60(i)(1), a description of the methods, models and assumptions used by the utility to prepare its peak load (MW) and energy sales (MWh) forecasts and the variables used in the models is provided in the pages named 'Methodology 1' and 'Methodology 2' of the Duke Energy Carolinas 2012 Forecast book located in Appendix B. Also, per NCUC Rule R8-60(i)(1)(A), a forecast of customers by each customer class and a forecast of energy sales (kWh) by each customer class is provided in the 2012 Forecast book located in Appendix B.

A tabulation of the utility's forecasts for a 20 year period, including peak loads for summer and winter seasons of each year and annual energy forecasts, both with and without the impact of utility-sponsored energy efficiency programs are shown below in Tables 3.E and 3.F.

Load duration curves, with and without utility-sponsored energy efficiency programs, follow Tables 3.E and 3.F, and are shown as Charts 3.A and 3.B.

The values in those tables reflect the loads that Duke Energy Carolinas is contractually obligated to provide and cover the period from 2012 to 2032.

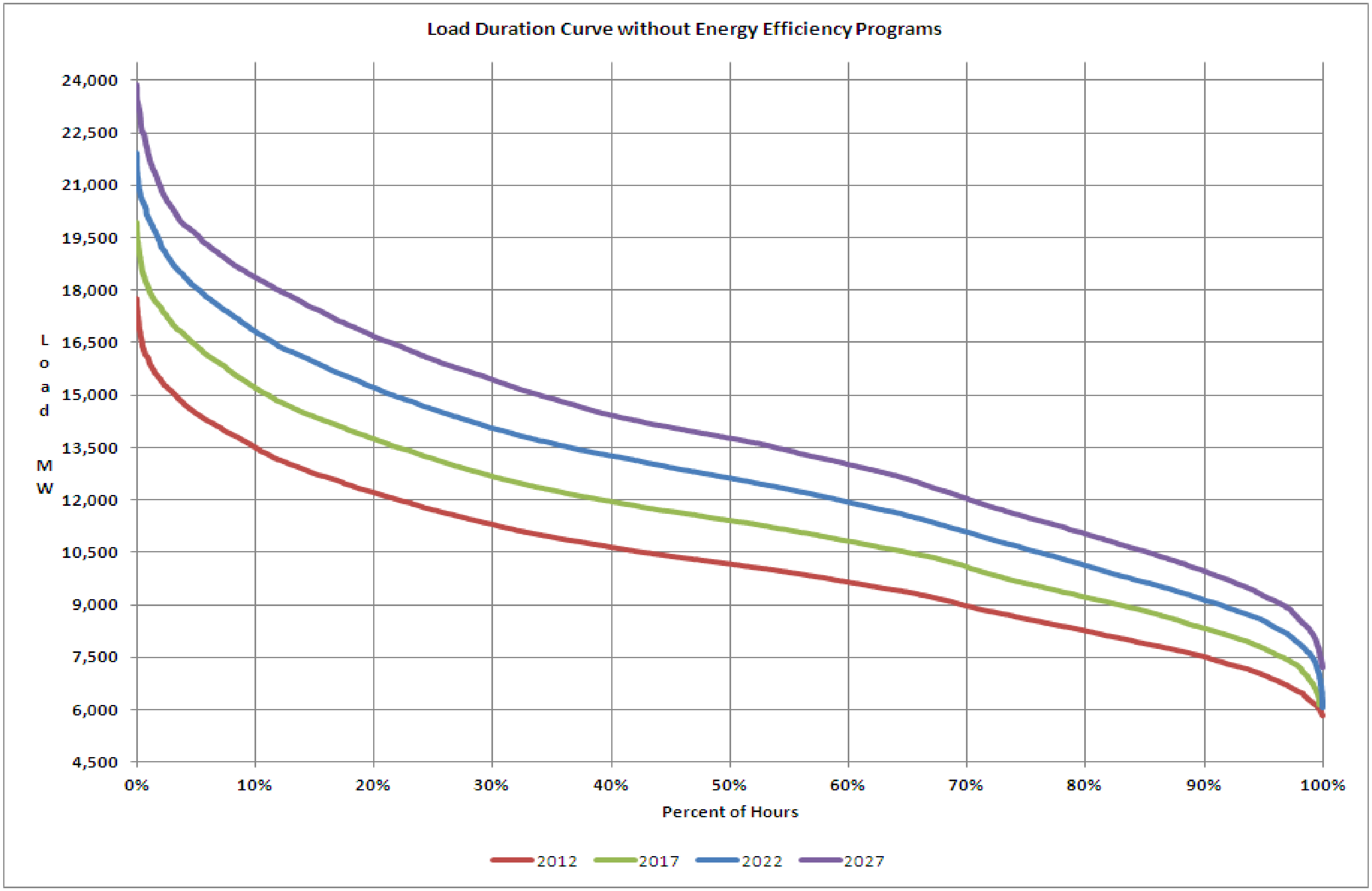
The current 20-year forecast of the needs of the retail and wholesale customer classes, which does not include the impact of new Duke Energy Carolinas energy efficiency programs, projects a compound annual growth rate of 1.9% in the summer peak demand, while winter peaks are forecasted to grow at 1.9%. The forecasted compound annual growth rate for energy is 2.0% before energy efficiency program impacts are subtracted.

If the impacts of new Duke Energy Carolinas energy efficiency programs are included, the projected compound annual growth rate for the summer peak demand is 1.7%, while winter peaks are forecasted to grow at a rate of 1.7%. The forecasted compound annual growth rate for energy is 1.6% after the impacts of energy efficiency programs have been subtracted.

Table 3.E
Load Forecast without Energy Efficiency Programs (at Generation)

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2012	17,745	17,086	90,572
2013	18,107	17,443	92,210
2014	18,554	17,868	94,402
2015	19,003	18,295	96,744
2016	19,486	18,744	99,147
2017	19,947	19,224	101,536
2018	20,386	19,672	103,975
2019	20,830	20,112	106,233
2020	21,176	20,474	108,141
2021	21,552	20,764	110,043
2022	21,921	21,179	111,979
2023	22,296	21,527	113,922
2024	22,673	21,880	115,894
2025	23,073	22,260	117,910
2026	23,435	22,585	119,972
2027	23,859	22,958	122,126
2028	24,260	23,418	124,352
2029	24,643	23,816	126,531
2030	25,051	24,209	128,747
2031	25,483	24,628	131,042
2032	25,905	25,005	133,453

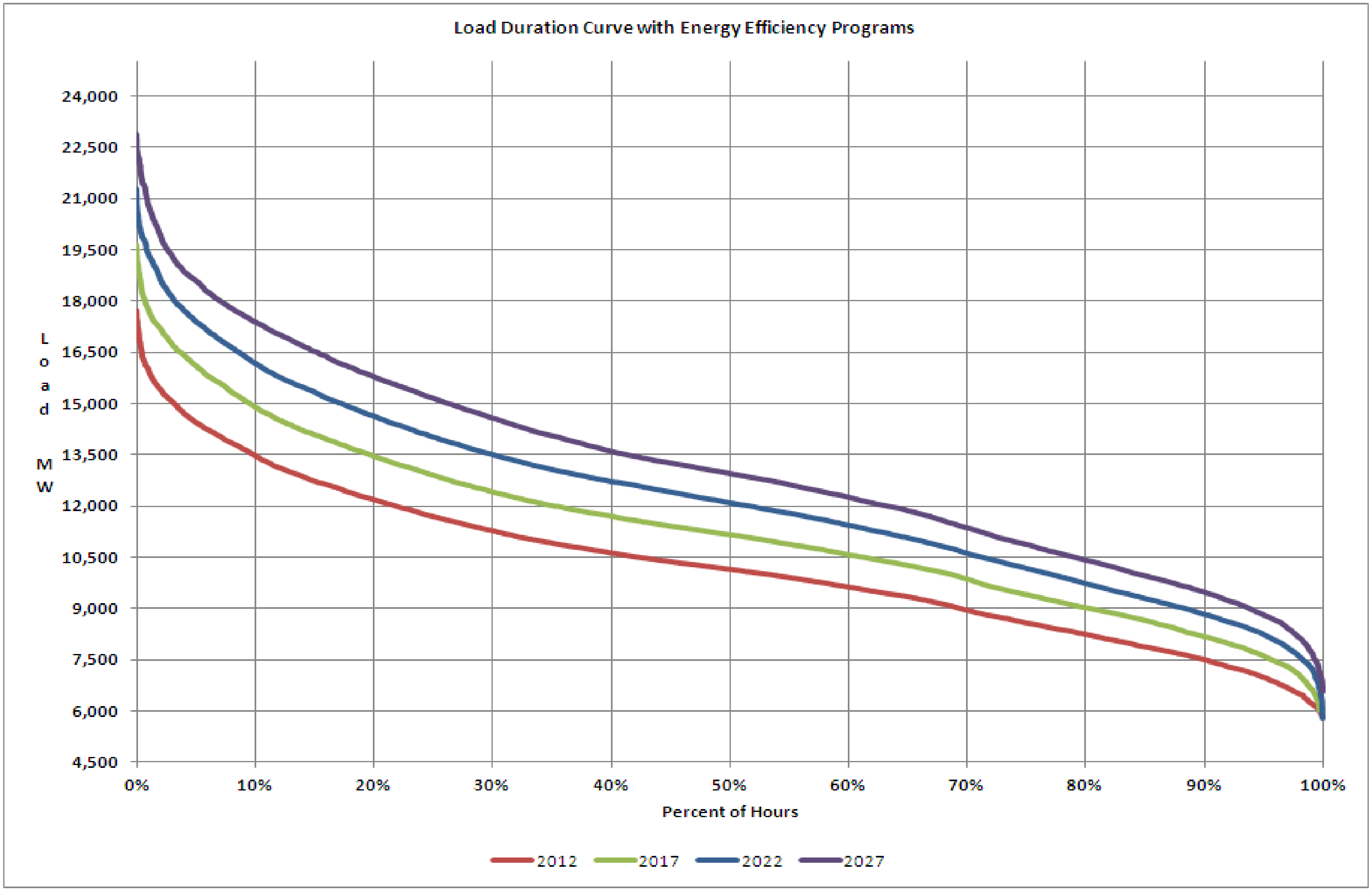
Chart 3.A- Load Duration Curves without Energy Efficiency



<u>Table 3.F</u>
Load Forecast with Energy Efficiency Programs (at Generation)

YEAR	SUMMER (MW)	WINTER (MW)	ENERGY (GWH)
2012	17,716	17,069	90,416
2013	18,043	17,383	91,741
2014	18,437	17,759	93,559
2015	18,795	18,130	95,499
2016	19,239	18,526	97,487
2017	19,630	18,921	99,418
2018	20,002	19,303	101,399
2019	20,379	19,677	103,200
2020	20,638	19,985	104,650
2021	20,967	20,197	106,093
2022	21,268	20,546	107,571
2023	21,577	20,828	109,056
2024	21,888	21,117	110,570
2025	22,219	21,446	112,128
2026	22,499	21,706	113,732
2027	22,871	21,994	115,427
2028	23,208	22,391	117,195
2029	23,520	22,720	118,916
2030	23,861	23,048	120,674
2031	24,227	23,425	122,511
2032	24,585	23,740	124,464

Chart 3.B - Load Duration Curves with Energy Efficiency



4. ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

Current Energy Efficiency and Demand-Side Management Programs

In May 2007, Duke Energy Carolinas filed its application for approval of Energy Efficiency and Demand Side Management programs under its save-a-watt initiative. The Company received the final order for approval for these programs from the NCUC in July 2010 and from the Public Service Commission of South Carolina (PSCSC) in May 2009.

Duke Energy Carolinas uses EE and DSM programs to help manage customer demand in an efficient, cost-effective manner. These programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response, and level and frequency of customer participation. In general, programs are offered in two primary categories: EE programs that reduce energy consumption and DSM programs that reduce energy demand (demand-side management or demand response programs and certain rate structure programs). The following are the current EE and DSM programs in place in the Carolinas:

Demand Response – Direct Load Control Curtailment Programs

These programs can be dispatched by the utility and have the highest level of certainty. Once a customer agrees to participate in a demand response load control curtailment program, the Company controls the timing, frequency, and nature of the load response. Duke Energy Carolinas' current direct load control curtailment programs are:

- **Power Manager® -** Power Manager® is a residential direct load control program. Participants receive billing credits during the billing months of July through October in exchange for allowing Duke Energy Carolinas the right to cycle their central air conditioning systems and, additionally, to interrupt the central air conditioning when the Company has capacity needs.

Demand Response – Interruptible and Related Rate Structures

These programs rely either on the customer's ability to respond to a utility-initiated signal requesting curtailment or on rates with price signals that provide an economic incentive to reduce or shift load. Timing, frequency and nature of the load response depend on customers' actions after notification of an event or after receiving pricing signals. Duke Energy Carolinas' current interruptible and time-of-use curtailment programs include:

- **Interruptible Power Service (IS)** (North Carolina Only) **-** Participants agree contractually to reduce their electrical loads to specified levels upon request by Duke Energy Carolinas. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

- **Standby Generator Control (SG)** (North Carolina Only) **-** Participants agree contractually to transfer electrical loads from the Duke Energy Carolinas source to their standby generators upon request by Duke Energy Carolinas. The generators in this program do not operate in parallel with the Duke Energy Carolinas system and therefore, cannot "backfeed" (i.e., export power) into the Duke Energy Carolinas system. Participating customers receive payments for capacity and/or energy, based on the amount of capacity and/or energy transferred to their generators.

- **PowerShare®** is a non-residential curtailment program consisting of four options: an emergency only option for curtailable load (PowerShare® Mandatory), an emergency only option for load curtailment using on-site generators (PowerShare® Generator), an economic based voluntary option (PowerShare® Voluntary), and a combined emergency and economic option that allows for increased notification time of events (PowerShare® CallOption).

    - PowerShare® Mandatory: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail during utility-initiated emergency events. Participants also receive energy credits for the load curtailed during events. Customers enrolled may also be enrolled in PowerShare® Voluntary and eligible to earn additional credits.

    - PowerShare® Generator: Participants in this emergency only option will receive capacity credits monthly based on the amount of load they agree to curtail (i.e. transfer to their on-site generator) during utility-initiated emergency events and their performance during monthly test hours. Participants also receive energy credits for the load curtailed during events.
    - PowerShare® Voluntary: Enrolled customers will be notified of pending emergency or economic events and can log on to a Web site to view a posted energy price for that particular event. Customers will then have the option to participate in the event and will be paid the posted energy credit for load curtailed.

    - PowerShare® CallOption: This DSM program offers a participating customer the ability to receive credits when the customer agrees, at the Company's request, to reduce and maintain its load by a minimum of 100 kW during Emergency and/or Economic Events. Credits are paid for the load available for curtailment, and charges are applicable when the customer fails to reduce load in accordance with the participation option it has selected. Participants are obligated to curtail load during emergency events. CallOption offers four participation options to customers: PS 0/5, PS 5/5, PS 10/5 and PS 15/5. All options include a limit of five Emergency Events and set a limit for Economic Events to 0, 5, 10 and 15 respectively.

- **Rates using price signals**

  - **Residential Time-of-Use (including a Residential Water Heating rate)**
    This category of rates for residential customers incorporates differential seasonal and time-of-day pricing that encourages customers to shift electricity usage from on-peak time periods to off-peak periods. In addition, there is a Residential Water Heating rate for off-peak water heating electricity use.

  - **General Service and Industrial Optional Time-of-Use rates**
    This category of rates for general service and industrial customers incorporates differential seasonal and time-of-day pricing that encourages customers to use less electricity during on-peak time periods and more during off-peak periods.

  - **Hourly Pricing for Incremental Load**
    This category of rates for general service and industrial customers incorporates prices that reflect Duke Energy Carolinas' estimation of hourly marginal costs. In addition, a portion of the customer's bill is calculated under their embedded-cost rate. Customers on this rate can choose to modify their usage depending on hourly prices.

Energy Efficiency Programs

These programs are typically non-dispatchable education or incentive programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All effects of these existing programs are reflected in the customer load forecast. Duke Energy Carolinas' existing EE programs include:

- **Residential Energy Assessments**

  The Residential Energy Assessments program includes two separate measures: (1) Personalized Energy Report (PER) and (2) Home Energy House Call.

  The PER program is a residential energy efficiency program that provides single family home customers with a customized report about their home and family and how they use energy. In addition, the customer receives compact fluorescent lights (CFLs) as an incentive to participate in the program.

The PER program requires customers to provide information about their home, number of occupants, equipment and energy usage and has two variations:

- A mailed offer where customers are asked to complete an included energy survey and mail it back to Duke Energy or complete the same survey online. Customers mailing the energy survey receive their PER in the mail and those completing it online receive their PER online as a printable PDF document.

- An online offer to our customers that have signed into Duke Energy's Online Services (OLS) bill pay and view environment. Online participants complete their energy survey online get their PER online as a printable PDF.

Home Energy House Call (HEHC) is a free in-home assessment designed to help our customers learn about home energy usage and how to save on monthly bills. The program provides personalized information unique to the customer's home and energy practices. An energy specialist visits the customer's home to analyze the total home energy usage and to pinpoint energy saving opportunities. An energy specialist will also explain how to improve the heating and cooling comfort levels, check for air leaks, examine insulation levels, review appliances, help the customer preserve the environment for the future and keep electric costs low. A customized report is prepared, explaining the steps the customer can take to increase efficiency. As a part of the Home Energy House Call program, customers receive an Energy Efficiency Starter Kit. At the request of the customer, the energy specialist can install the efficiency items to allow the customer to begin saving immediately.

- **Low Income Energy Efficiency and Weatherization Program**
  The purpose of this program is to assist low income residential customers with energy efficiency measures to reduce energy usage through energy efficiency kits or through assistance in the cost of energy efficient equipment or weatherization measures.

- **Energy Efficiency Education Program for Schools**
  The purpose of this program is to educate students about sources of energy and energy efficiency in homes and schools through a curriculum provided to public and private schools. This curriculum includes lesson plans, energy efficiency

materials, and energy audits.

- **Residential Smart $aver® Energy Efficient Products Program**
  The Smart $aver® Program provides incentives to residential customers who purchase energy-efficient equipment. The program has three components – CFLs, high-efficiency air conditioning equipment and tune and seal measures.

  CFLs
  The CFL program is designed to offer incentives to customers and increase energy efficiency by installing CFLs in high use fixtures in the home. The incentives have been offered in a variety of ways. The first deployment of this program distributed free coupons to be redeemed by the customer at a variety of retail stores. Later deployments used business reply cards and a web-based on-demand ordering tool where CFLs were shipped directly to the customer's home.

  Heating Ventilation & Air Conditioning (HVAC) and Heat Pump
  The residential air conditioning program provides incentives to customers, builders, and heating contractors (HVAC dealers) to promote the use of high-efficiency air conditioners and heat pumps. The program is designed to increase the efficiency of air conditioning systems in new homes and for replacements in existing homes.

  Tune and Seal Measures (Approved in South Carolina only)
  Partnering with HVAC dealers, the program pays incentives to partially offset the cost of air conditioner and heat pump tune ups and duct sealing. This is a new program and has not been previously offered in any of Duke Energy's jurisdictions. Projected impacts of this program were included in the analysis of generation needs.

- **Residential Neighborhood Program**
  Program that targets low income neighborhoods providing high impact direct install measures (CFLs, pipe and water heater wrap, low flow aerators and showerheads, HVAC filters and air infiltration sealing) and energy efficiency education. Projected impacts of this program were included in the analysis of generation needs.

- **Appliance Recycling Program (Approved in South Carolina only)**
  This is a program to incentivize households to remove old inefficient refrigerators and freezers and have those units properly recycled. Projected impacts of this program were included in the analysis of generation needs.

- **My Home Energy Report (Approved in South Carolina only)**
  The purpose of this program is to provide comparative usage data for similar residences in the same geographic area to motivate customers to better manage and reduce energy usage. The program assists residential customers in assessing their energy usage and provides recommendations for more efficient use of energy in their homes. The program also helps to identify those customers who could benefit most by investing in new energy efficiency measures, undertaking more energy efficient practices and participating in Duke Energy programs.

- **Smart $aver® for Non-Residential Customers**
  The purpose of this program is to encourage the installation of high-efficiency equipment in new and existing non-residential establishments. The program provides incentive payments to offset a portion of the higher cost of energy-efficient equipment. The following types of equipment are eligible for incentives as part of the Prescriptive program: high-efficiency lighting, high-efficiency air conditioning equipment, high-efficiency motors, high-efficiency pumps, variable frequency drives, food services and process equipment. Customer incentives may be paid for other high-efficiency equipment as determined by the Company to be evaluated on a case-by-case basis through the Custom program.

The projected impacts from these programs are included in this year's assessment of generation needs.

Additional Programs Being Considered
A high-level overview is provided below.

- **PowerShare® CallOption 200**
  This new CallOption, high involvement offer is targeted at customers with very flexible load with load curtailment potential of up to 200 hours of economic load curtailment each year. This option will function essentially in the same manner as the Company's other CallOption offers. However, customers who participate will experience considerably more requests for load curtailment for economic purposes. Participants will remain obligated to curtail load during up to 5 emergency events.

The following pilot programs have been approved:

- **Residential Retrofit**
  This program was approved in North Carolina in Docket E-7, Sub 952 on January 25, 2011. The Residential Retrofit program is designed to assist residential

customers in assessing their energy usage, to provide recommendations for more efficient use of energy in their homes and to encourage the installation of energy efficient improvements by offsetting a portion of the cost of implementing the recommendations from the assessment. Projected impacts of this pilot program were included in the Company's analysis of generation needs.

- **Smart Energy Now (SEN)**
  The SEN pilot program was approved by the NCUC in Docket E-7, Sub 961 on February 14, 2011 and is designed to reduce energy consumption within the commercial office space located in Charlotte City Center through community engagement leading to behavioral modification. In order to enable building managers and occupants to effectively make these behavioral modifications, they will be provided with additional energy consumption information and actionable efficiency recommendations. Projected impacts of this pilot were also included in the Company's analysis of generation needs.

The following pilot program is being proposed:

- **My Energy Manager (MyEM)**
  MyEM is a residential energy management solution designed for home owners with broadband internet service. The product offers energy efficiency and demand response benefits through a Wi-Fi enabled thermostat that will manage a customer's air conditioning system by providing schedules, modes (such as home/away/vacation), energy savings tips, messages, and alerts. The customer will have the tools to access and control their thermostat through any web browser or by downloading an "app" on their smart phone. In addition, it will provide customers with the opportunity to participate in demand response events. Overall, this product will provide simple, intuitive, and effective tools that will enable the customer to reduce and manage their overall energy usage.

Future EE and DSM programs

In addition to the programs and pilots listed above, Duke Energy Carolinas is actively working to add new programs to our portfolio that have not yet been developed. Estimates of the impacts of these yet-to-be-developed programs have been included in this year's analysis of generation needs.

EE and DSM Program Screening

The Company uses the DSMore model to evaluate the costs, benefits, and risks of DSM and EE programs and measures. DSMore is a financial analysis tool designed to estimate the value of DSM and EE measures at an hourly level across distributions of weather conditions and/or energy costs or prices. By examining projected program performance and cost effectiveness over a wide variety of weather and cost conditions, the Company is in a better position to measure the risks and benefits of employing DSM and EE measures versus traditional generation capacity additions, and further, to ensure that DSM resources are compared to supply side resources on a level playing field.

The analysis of energy efficiency and demand side management cost-effectiveness has traditionally focused primarily on the calculation of specific metrics, often referred to as the California Standard tests: Utility Cost Test (UCT), Rate Impact Measure (RIM) Test, Total Resource Cost (TRC) Test, and Participant Test (PCT). DSMore provides the results of those tests for any type of EE or DSM program.

- The UCT compares utility benefits (avoided costs) to the costs incurred by the utility to implement the program, and does not consider other benefits such as participant savings or societal impacts. This test compares the cost (to the utility) to implement the measures with the savings or avoided costs (to the utility) resulting from the change in magnitude and/or the pattern of electricity consumption caused by implementation of the program. Avoided costs are considered in the evaluation of cost-effectiveness based on the projected cost of power, including the projected cost of the utility's environmental compliance for known regulatory requirements. The cost-effectiveness analyses also incorporate avoided transmission and distribution costs, and load (line) losses.

- The RIM Test, or non-participants test, indicates if rates increase or decrease over the long-run as a result of implementing the program.

- The TRC Test compares the total benefits to the utility and to participants relative to the costs to the utility to implement the program along with the costs to the participant. The benefits to the utility are the same as those computed under the UCT. The benefits to the participant are the same as those computed under the Participant Test, however, customer incentives are considered to be a pass-through benefit to customers. As such, customer incentives or rebates are not included in the TRC.

- The Participant Test evaluates programs from the perspective of the program's participants. The benefits include reductions in utility bills, incentives paid by the utility and any state, federal or local tax benefits received.

The use of multiple tests can ensure the development of a reasonable set of DSM and EE programs and indicate the likelihood that customers will participate.

Energy Efficiency and Demand-Side Management Programs

Duke Energy Carolinas has made a strong commitment to EE and DSM. The Company recognizes EE and DSM as a reliable, valuable resource that is an option in the portfolio available to meet customers' growing need for electricity along with coal, nuclear, natural gas, and renewable energy. These EE and DSM programs help customers meet their energy needs with less electricity, less cost and less environmental impact. The Company will manage EE and DSM to provide customers with universal access to these services and new technology. Duke Energy Carolinas has the expertise, infrastructure, and customer relationships to produce results and make it a significant part of its resource mix. Duke Energy Carolinas is committed to develop, implement, adjust as needed, and verify the results of innovative EE programs for the benefit of its customers.

In 2011, Duke Energy commissioned an independent Market Potential Study for both the North Carolina and South Carolina service territories. This study was prepared by Forefront Economics Inc. and was completed in December of 2011. The results of this Market Potential Study were incorporated into the Energy Efficiency forecasts included in the 2012 IRP.

The Duke Energy Carolinas' approved EE plan is consistent with the requirement set forth in the Cliffside Unit 6 CPCN Order to invest 1% of annual retail electricity revenues in EE and DSM programs, subject to the results of ongoing collaborative workshops and appropriate regulatory treatment. For the period between the deployment of the Company's save-a-watt portfolio in 2009 and December 31, 2011, Duke Energy's EE and DSM programs have reduced overall demand, including line losses, by approximately 1,159,000 MWh and have added the capability to reduce the Summer Peak by over 800 MW. However, pursuing EE and DSM initiatives will not meet all growing demands for electricity. The Company still envisions the need to secure additional nuclear and natural gas generation, as well as cost-effective renewable generation, but the EE and DSM programs offered by Duke Energy Carolinas could address approximately half of the Company's projected 2016 new resource need, if such programs perform as expected.

Table 4.A provides the base case projected load impacts of the EE and DSM programs through 2032. These load impacts were included in the base case IRP analysis. The Company assumes total EE savings will continue to grow on an annual basis through 2032, however the components of future programs are uncertain at this time and will be informed by the experience gained under the current plan. This table also includes a separate column showing the total annual MWh load reductions associated with EE programs that have been added since the inception of the EE programs in 2009. The projected MW load impacts from the DSM programs are based upon the Company's continuing, as well as the new, DSM programs. The MW capacity projections have increased from last year due to stronger projected growth in the PowerShare® programs.

The projected total annual MWh load reductions associated with EE programs included in this base case are more than 10% higher than those included in the 2011 IRP base case, primarily due to updated expectations of the performance of the EE programs beyond the initial 5 year planning period. The projected base case for this 2012 IRP reaches approximately the same total cumulative achievements, including actual achievements since 2009, by 2023 that were projected to be achieved by 2031 in the 2011 IRP.

Table 4.B provides a high case load impact scenario from the Company's EE and DSM programs. Compared to the 2011 IRP, the new high case represents a significant increase in the amount of EE and DSM impacts that are modeled, consistent with the Company's merger settlement, under which the Company will aspire to more aggressive cumulative EE achievement over the period 2014-2018[2] and annual incremental achievement beginning in 2015 of 1% of prior year retail electricity sales. The impacts in this high case are assumed to level off after 2031 because the projection reaches the theoretical economic potential as determined in the Market Potential Study completed in 2011. However, Duke Energy Carolinas is committed to ongoing efforts to add incremental savings to the extent they are cost effective and customers embrace those measures. For DSM programs, the load impacts are increased to reflect higher participation projections in the Company's demand response programs.

The level of energy efficiency impacts are not ultimately the decision of the Company. Driven by the structure of cost recovery and incentive mechanisms and the commitment to minimize overall costs to customers, the Company is committed to maximizing the implementation of cost-effective energy efficiency and demand response measures in its territory. However, while the Company will seek to make programs maximally attractive to customers, customers make individual participation decisions based on a variety of

[2] The Duke-Progress merger commitment regarding energy efficiency requires that Duke make a good faith effort to achieve a cumulative savings target of 7% of retail electricity sales over the five-year time period of 2014-2018.

factors. Therefore, for planning purposes, the Company models the base EE/DSM case assuming limited customer participation until the rate of program adoption is confirmed. The high EE/DSM case reflects more aggressive program achievements consistent with the merger settlement.

Table 4.C incorporates December 31, 2011 participation levels for all demand response programs and the capability of these programs projected for the summer of 2012.

Table 4.A Load Impacts of EE and DSM Programs – Base Case

Energy Efficiency and Demand Side Management Programs

	Energy Efficiency			Demand Response Peak MW Summer Peak MW					
Year	Total Annual MWh Load Reduction (including measures added in 2012 and beyond)	Total Annual MWh Load Reduction (including measures added since 2009 EE program inception)	Summer Peak MW	IS	SG	PowerShare	PowerManager	Total	Total Summer Peak MW Impacts
2009		70,782							
2010		591,969							
2011		1,159,117							
2012	312,067	1,471,184	29	119	44	390	261	814	843
2013	626,576	1,785,693	62	95	5	470	305	875	937
2014	1,059,768	2,218,885	117	90	5	500	357	953	1,070
2015	1,430,299	2,589,416	181	85	5	527	409	1,026	1,207
2016	1,888,405	3,047,522	247	81	5	549	416	1,050	1,297
2017	2,346,512	3,505,629	317	77	4	571	419	1,071	1,388
2018	2,804,618	3,963,735	384	77	4	571	419	1,071	1,455
2019	3,262,725	4,421,842	451	77	4	571	419	1,071	1,523
2020	3,720,831	4,879,948	517	77	4	571	419	1,071	1,588
2021	4,178,938	5,338,055	585	77	4	571	419	1,071	1,657
2022	4,637,044	5,796,161	652	77	4	571	419	1,071	1,724
2023	5,095,151	6,254,268	720	77	4	571	419	1,071	1,791
2024	5,553,257	6,712,374	785	77	4	571	419	1,071	1,856
2025	6,011,363	7,170,481	854	77	4	571	419	1,071	1,925
2026	6,469,470	7,628,587	921	77	4	571	419	1,071	1,992
2027	6,927,576	8,086,693	988	77	4	571	419	1,071	2,060
2028	7,385,683	8,544,800	1,053	77	4	571	419	1,071	2,124
2029	7,843,789	9,002,906	1,123	77	4	571	419	1,071	2,194
2030	8,301,896	9,461,013	1,190	77	4	571	419	1,071	2,261
2031	8,760,002	9,919,119	1,257	77	4	571	419	1,071	2,328
2032	9,218,109	10,377,226	1,320	77	4	571	419	1,071	2,392

Table 4.B Load Impacts of EE and DSM Programs – High Case

Energy Efficiency and Demand Side Management Programs

	Energy Efficiency			Demand Response Peak MW Summer Peak MW					
Year	Total Annual MWh Load Reduction (including measures added in 2012 and beyond)	Total Annual MWh Load Reduction (including measures added since 2009 EE program inception)	Summer Peak MW	IS	SG	PowerShare	PowerManager	Total	Total Summer Peak MW Impacts
2009		70,782							
2010		591,969							
2011		1,159,117							
2012	312,067	1,471,184	29	119	44	390	261	815	844
2013	626,576	1,785,693	62	100	11	470	307	888	950
2014	1,366,576	2,525,693	139	95	10	523	362	990	1,129
2015	2,186,219	3,345,336	257	90	10	576	416	1,091	1,349
2016	3,014,102	4,173,219	387	86	9	613	425	1,133	1,520
2017	3,850,654	5,009,771	514	81	9	651	430	1,171	1,684
2018	4,696,074	5,855,191	637	81	9	651	431	1,172	1,809
2019	5,550,159	6,709,276	762	81	9	651	431	1,172	1,934
2020	6,412,955	7,572,072	885	81	9	651	431	1,172	2,057
2021	7,284,387	8,443,504	1,015	81	9	651	431	1,172	2,187
2022	8,164,725	9,323,842	1,143	81	9	651	431	1,172	2,315
2023	9,054,089	10,213,206	1,273	81	9	651	431	1,172	2,445
2024	9,952,555	11,111,672	1,401	81	9	651	431	1,172	2,573
2025	10,860,095	12,019,212	1,537	81	9	651	431	1,172	2,709
2026	11,776,729	12,935,846	1,671	81	9	651	431	1,172	2,843
2027	12,703,074	13,862,191	1,806	81	9	651	431	1,172	2,978
2028	13,639,302	14,798,419	1,937	81	9	651	431	1,172	3,109
2029	14,586,209	15,745,326	2,081	81	9	651	431	1,172	3,253
2030	15,544,266	16,703,383	2,220	81	9	651	431	1,172	3,392
2031	16,513,125	17,672,242	2,361	81	9	651	431	1,172	3,533
2032	16,513,125	17,672,242	2,426	81	9	651	431	1,172	3,598

Table 4.D Current DSM Program Information

DSM Program Participation and Capability

DSM Program Name	Participation as of 12/31/11 (# of participants)	2012 Estimated Summer IRP Capability (MW)
IS	64	119
SG	93	44
PowerShare Mandatory	151	373
PowerShare Generator	8	17
PowerShare Voluntary	6	N/A
PowerShare CallOption		
Level 0/5	0	0
Level 5/5	0	0
Level 10/5	0	0
Level 15/5	0	0
Power Manager	192,062	261
Total	192,384	814

Programs Evaluated but Rejected

Duke Energy Carolinas has not rejected any programs as a result of its EE and DSM program screening.

Looking to the Future

DSM Implementation Effectiveness – The Company performed an initial review of the effectiveness of varying amounts of demand response in 2011. The review is ongoing to help shape Duke Energy Carolinas' portfolio perspective of demand response programs.

Grid Modernization – Duke Energy is pursuing implementation of grid modernization throughout the enterprise. The recent $200 million grant awarded to Duke Energy from the US DOE helps further that goal. Grid modernization is a mechanism to further enable adoption and market penetration of EE, DSM and plug-in electric vehicle (PEVs) programs. In order to meet and support EE and DSM goals, the NCUC proposed a requirement to include grid modernization impacts in the IRP for North Carolina electric utilities (including Duke Energy Carolinas) in Docket E-100, Sub 126. On April 11, 2012, the NCUC issued its *Order Amending Commission Rule R8-60 and Adopting Commission Rule R8-60.1 in the matter of Integrated Resource Planning in North Carolina* addressing Smart Grid Technology Plans, where the NCUC ordered that each utility provide information regarding the impacts of its smart grid deployment plan on the overall IRP. Distribution Automation is a part of Duke Energy Carolinas grid modernization program. The projected increases in DSM impacts due to grid modernization impacts incorporated into the 2012 IRP results in a corresponding 40 MW decrease in customers' capacity needs by 2015. Over a 10 year period beginning in 2014, the projected impacts rise to 135 MW.

Also per the above NCUC order, by July 1, 2013 and every two years thereafter, each utility subject to Rule R8-60 shall file with the NCUC its smart grid technology plan. Significant amendments or revisions to a smart grid technology plan shall be reported to the NCUC in each year in which the biennial smart grid technology plan is not required to be filed. Duke Energy Carolinas will comply with this requirement and a discussion of its smart grid technology plan will be included in the 2013 IRP.

5. SUPPLY-SIDE RESOURCES

A. Existing Generation Plants in Service

Duke Energy Carolinas' generation portfolio includes a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve its customers. Duke Energy Carolinas owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements. In 2011, Duke Energy Carolinas' nuclear and coal-fired generating units met the vast majority of customer needs by providing 52.2% and 45.7%, respectively, of Duke Energy Carolinas' energy from generation. Hydroelectric generation, CT generation, solar generation, long term PPAs, and economical purchases from the wholesale market supplied the remainder.

Existing Resources

The tables below list the Duke Energy Carolinas plants in service in North Carolina (NC) and South Carolina (SC) with plant statistics, and the system's total generating capability.

Table 5.A

North Carolina [a,b,c,d,e]

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Allen	1	162.0	167.0	Belmont, N.C.	Conventional Coal
Allen	2	162.0	167.0	Belmont, N.C.	Conventional Coal
Allen	3	261.0	270.0	Belmont, N.C.	Conventional Coal
Allen	4	276.0	282.0	Belmont, N.C.	Conventional Coal
Allen	5	266.0	275.0	Belmont, N.C.	Conventional Coal
Allen Steam Station		**1127.0**	**1161.0**		
Belews Creek	1	1110.0	1135.0	Belews Creek, N.C.	Conventional Coal
Belews Creek	2	1110.0	1135.0	Belews Creek, N.C.	Conventional Coal
Belews Creek Steam Station		**2220.0**	**2270.0**		
Buck	5	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck	6	128.0	131.0	Salisbury, N.C.	Conventional Coal
Buck Steam Station		**256.0**	**262.0**		
Cliffside	5	552.0	556.0	Cliffside, N.C.	Conventional Coal
Cliffside Steam Station		**552.0**	**556.0**		
Marshall	1	380.0	380.0	Terrell, N.C.	Conventional Coal
Marshall	2	380.0	380.0	Terrell, N.C.	Conventional Coal
Marshall	3	658.0	658.0	Terrell, N.C.	Conventional Coal
Marshall	4	660.0	660.0	Terrell, N.C.	Conventional Coal
Marshall Steam Station		**2078.0**	**2078.0**		
Riverbend	4	94.0	96.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	5	94.0	96.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	6	133.0	136.0	Mt. Holly, N.C.	Conventional Coal
Riverbend	7	133.0	136.0	Mt. Holly, N.C.	Conventional Coal
Riverbend Steam Station		**454.0**	**464.0**		
TOTAL N.C. CONVENTIONAL COAL		**6687.0 MW**	**6791.0 MW**		
Buck	7C	25.0	30.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck	8C	25.0	30.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck	9C	12.0	15.0	Salisbury, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Buck Station CTs		**62.0**	**75.0**		
Dan River	4C	0.0	0.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River	5C	24.0	31.0	Eden, N.C.	Natural Gas/Oil-Fired

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
					Combustion Turbine
Dan River	6C	24.0	31.0	Eden, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Dan River Station CTs		**48.0**	**62.0**		
Lincoln	1	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	2	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	3	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	4	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	5	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	6	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	7	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	8	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	9	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	10	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	11	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	12	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	13	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	14	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	15	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln	16	79.2	93.0	Stanley, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Lincoln Station CTs		**1267.2**	**1488.0**		
Riverbend	8C	0.0	0.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	9C	22.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	10C	22.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Riverbend	11C	20.0	30.0	Mt. Holly, N.C.	Natural Gas/Oil-Fired Combustion Turbine

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Riverbend Station CTs		**64.0**	**90.0**		
Rockingham	1	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	2	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	3	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	4	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham	5	165.0	165.0	Rockingham, N.C.	Natural Gas/Oil-Fired Combustion Turbine
Rockingham CTs		**825.0**	**825.0**		
Buck	CT11	165.0	170.0	Salisbury, N.C.	Natural Gas CT Combined Cycle
Buck	CT12	165.0	170.0	Salisbury, N.C.	Natural Gas CT Combined Cycle
Buck	ST10	290.0	300.0	Salisbury, N.C.	Natural Gas CT Combined Cycle
Buck CTCC		**620.0**	**640.0**		
Total N.C. COMB. TURBINE		**2886.2 MW**	**3180.0 MW**		
McGuire	1	1100.0	1156.0	Huntersville, N.C.	Nuclear
McGuire	2	1100.0	1156.0	Huntersville, N.C.	Nuclear
McGuire Nuclear Station		**2200.0**	**2312.0**		
TOTAL N.C. NUCLEAR		**2200.0 MW**	**2312.0 MW**		
Bridgewater	1	15.0	15.0	Morganton, N.C.	Hydro
Bridgewater	2	15.0	15.0	Morganton, N.C.	Hydro
Bridgewater	3	1.5	1.5	Morganton, N.C.	Hydro
Bridgewater Hydro Station		**31.5**	**31.5**		
Bryson City	1	0.48	0.48	Whittier, N.C.	Hydro
Bryson City	2	0	0	Whittier, N.C.	Hydro
Bryson City Hydro Station		**0.48**	**0.48**		
Cowans Ford	1	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	2	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	3	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford	4	81.3	81.3	Stanley, N.C.	Hydro
Cowans Ford Hydro Station		**325.2**	**325.2**		
Lookout Shoals	1	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals	2	9.3	9.3	Statesville, N.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Lookout Shoals	3	9.3	9.3	Statesville, N.C.	Hydro
Lookout Shoals Hydro Station		**27.9**	**27.9**		
Mountain Island	1	14	14	Mount Holly, N.C.	Hydro
Mountain Island	2	14	14	Mount Holly, N.C.	Hydro
Mountain Island	3	17	17	Mount Holly, N.C.	Hydro
Mountain Island	4	17	17	Mount Holly, N.C.	
Mountain Island Hydro Station		**62.0**	**62.0**		
Oxford	1	20.0	20.0	Conover, N.C.	Hydro
Oxford	2	20.0	20.0	Conover, N.C.	Hydro
Oxford Hydro Station		**40.0**	**40.0**		
Rhodhiss	1	9.5	9.5	Rhodhiss, N.C.	Hydro
Rhodhiss	2	11.5	11.5	Rhodhiss, N.C.	Hydro
Rhodhiss	3	9.0	9.0	Rhodhiss, N.C.	Hydro
Rhodhiss Hydro Station		**30.0**	**30.0**		
Tuxedo	1	3.2	3.2	Flat Rock, N.C.	Hydro
Tuxedo	2	3.2	3.2	Flat Rock, N.C.	Hydro
Tuxedo Hydro Station		**6.4**	**6.4**		
Bear Creek	1	9.45	9.45	Tuckasegee, N.C.	Hydro
Bear Creek Hydro Station		**9.45**	**9.45**		
Cedar Cliff	1	6.4	6.4	Tuckasegee, N.C.	Hydro
Cedar Cliff Hydro Station		**6.4**	**6.4**		
Franklin	1	0	0	Franklin, N.C.	Hydro
Franklin	2	.6	.6	Franklin, N.C.	Hydro
Franklin Hydro Station		**.6**	**.6**		
Mission	1	0	0	Murphy, N.C.	Hydro
Mission	2	0	0	Murphy, N.C.	Hydro
Mission	3	0.6	0.6	Murphy, N.C.	Hydro
Mission Hydro Station		**0.6**	**0.6**		
Nantahala	1	50.0	50.0	Topton, N.C.	Hydro
Nantahala Hydro Station		**50.0**	**50.0**		
Tennessee Creek	1	9.8	9.8	Tuckasegee, N.C.	Hydro
Tennessee Creek Hydro Station		**9.8**	**9.8**		
Thorpe	1	19.7	19.7	Tuckasegee, N.C.	Hydro
Thorpe Hydro Station		**19.7**	**19.7**		
Tuckasegee	1	2.5	2.5	Tuckasegee, N.C.	Hydro
Tuckasegee Hydro Station		**2.5**	**2.5**		
Queens Creek	1	1.44	1.44	Topton, N.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Queens Creek Hydro Station		**1.44**	**1.44**		
TOTAL N.C. HYDRO		**623.97 MW**	**623.97 MW**		
TOTAL N.C. SOLAR		**8.43 MW**	**8.43 MW**	N.C.	Solar
TOTAL N.C. CAPABILITY		**12,405.60 MW**	**12,915.40 MW**		

Table 5.B
South Carolina [a,b,c,d,e]

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Lee	1	100.0	100.0	Pelzer, S.C.	Conventional Coal
Lee	2	100.0	102.0	Pelzer, S.C.	Conventional Coal
Lee	3	170.0	170.0	Pelzer, S.C.	Conventional Coal
Lee Steam Station		**370.0**	**372.0**		
TOTAL S.C. CONVENTIONAL COAL		**370.0 MW**	**372.0 MW**		
Buzzard Roost	6C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	7C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	8C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	9C	20.0	20.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	10C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	11C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	12C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	13C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	14C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost	15C	16.0	16.0	Chappels, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Buzzard Roost Station CTs		**176.0**	**176.0**		
Lee	7C	41.0	41.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee	8C	41.0	41.0	Pelzer, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Lee Station CTs		**82.0**	**82.0**		
Mill Creek	1	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	2	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	3	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	4	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	5	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Mill Creek	6	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	7	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek	8	74.42	92.4	Blacksburg, S.C.	Natural Gas/Oil-Fired Combustion Turbine
Mill Creek Station CTs		**595.4**	**739.2**		
TOTAL S.C. COMB TURBINE		**853.4 MW**	**997.2 MW**		
Catawba	1	1129.0	1163.0	York, S.C.	Nuclear
Catawba	2	1129.0	1163.0	York, S.C.	Nuclear
Catawba Nuclear Station		**2258.0**	**2326.0**		
Oconee	1	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	2	846.0	865.0	Seneca, S.C.	Nuclear
Oconee	3	846.0	865.0	Seneca, S.C.	Nuclear
Oconee Nuclear Station		**2538.0**	**2595.0**		
TOTAL S.C. NUCLEAR		**4796.0 MW**	**4921.0 MW**		
Jocassee	1	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee	2	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee	3	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee	4	195.0	195.0	Salem, S.C.	Pumped Storage
Jocassee Pumped Hydro Station		**780.0**	**780.0**		
Bad Creek	1	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	2	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	3	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek	4	340.0	340.0	Salem, S.C.	Pumped Storage
Bad Creek Pumped Hydro Station		**1360.0**	**1360.0**		
TOTAL PUMPED STORAGE		**2140.0 MW**	**2140.0 MW**		
Cedar Creek	1	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek	2	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek	3	15.0	15.0	Great Falls, S.C.	Hydro
Cedar Creek Hydro Station		**45.0**	**45.0**		
Dearborn	1	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn	2	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn	3	14.0	14.0	Great Falls, S.C.	Hydro
Dearborn Hydro Station		**42.0**	**42.0**		

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Fishing Creek	1	11.0	11.0	Great Falls, S.C.	Hydro
Fishing Creek	2	9.5	9.5	Great Falls, S.C.	Hydro
Fishing Creek	3	9.5	9.5	Great Falls, S.C.	Hydro
Fishing Creek	4	11.0	11.0	Great Falls, S.C.	Hydro
Fishing Creek	5	8.0	8.0	Great Falls, S.C.	Hydro
Fishing Creek Hydro Station		**49.0**	**49.0**		
Gaston Shoals	3	0	0	Blacksburg, S.C.	Hydro
Gaston Shoals	4	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	5	1.0	1.0	Blacksburg, S.C.	Hydro
Gaston Shoals	6	0	0	Blacksburg, S.C.	Hydro
Gaston Shoals Hydro Station		**2.0**	**2.0**		
Great Falls	1	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	2	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	3	0	0	Great Falls, S.C.	Hydro
Great Falls	4	0	0	Great Falls, S.C.	Hydro
Great Falls	5	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	6	3.0	3.0	Great Falls, S.C.	Hydro
Great Falls	7	0	0	Great Falls, S.C.	Hydro
Great Falls	8	0	0	Great Falls, S.C.	Hydro
Great Falls Hydro Station		**12.0**	**12.0**		
Rocky Creek	1	0	0	Great Falls, S.C.	Hydro
Rocky Creek	2	0	0	Great Falls, S.C.	Hydro
Rocky Creek	3	0	0	Great Falls, S.C.	Hydro
Rocky Creek	4	0	0	Great Falls, S.C.	Hydro
Rocky Creek	5	0	0	Great Falls, S.C.	Hydro
Rocky Creek	6	0	0	Great Falls, S.C.	Hydro
Rocky Creek	7	0	0	Great Falls, S.C.	Hydro
Rocky Creek	8	0	0	Great Falls, S.C.	Hydro
Rocky Creek Hydro Station		**0**	**0**		
Wateree	1	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	2	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	3	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	4	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree	5	17.0	17.0	Ridgeway, S.C.	Hydro
Wateree Hydro Station		**85.0**	**85.0**		
Wylie	1	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	2	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	3	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie	4	18.0	18.0	Fort Mill, S.C.	Hydro
Wylie Hydro Station		**72.0**	**72.0**		
99 Islands	1	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	2	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	3	1.6	1.6	Blacksburg, S.C.	Hydro

NAME	UNIT	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
99 Islands	4	1.6	1.6	Blacksburg, S.C.	Hydro
99 Islands	5	0	0	Blacksburg, S.C.	Hydro
99 Islands	6	0	0	Blacksburg, S.C.	Hydro
99 Islands Hydro Station		**6.4**	**6.4**		
Keowee	1	76.0	76.0	Seneca, S.C.	Hydro
Keowee	2	76.0	76.0	Seneca, S.C.	Hydro
Keowee Hydro Station		**152.0**	**152.0**		
TOTAL S.C. HYDRO		**465.4 MW**	**465.4 MW**		
TOTAL S.C. CAPABILITY		**8,624.8 MW**	**8,895.6 MW**		
NAME	**UNIT**	**SUMMER CAPACITY MW**	**WINTER CAPACITY MW**	**LOCATION**	**PLANT TYPE**

Table 5.C
Total Generation Capability [a,b,c,d,e]

NAME	SUMMER CAPACITY MW	WINTER CAPACITY MW
TOTAL DUKE ENERGY CAROLINAS GENERATING CAPABILITY	**21,030.4**	**21,811.0**

Note a: Unit information is provided by State, but resources are dispatched on a system-wide basis.

Note b: Summer and winter capability does not take into account reductions due to future environmental emission controls.

Note c: Summer and winter capability reflects system configuration as of April 4, 2012.

Note d: Catawba Units 1 and 2 capacity reflects 100% of the station's capability, and does not factor in the North Carolina Municipal Power Agency #1's (NCMPA#1) decision to sell or utilize its 832 MW retained ownership in Catawba.

Note e: The Catawba units' multiple owners and their effective ownership percentages are:

CATAWBA OWNER	PERCENT OF OWNERSHIP
Duke Energy Carolinas	19.246%
North Carolina Electric Membership Corporation (NCEMC)	30.754%
NCMPA#1	37.5%
Piedmont Municipal Power Agency (PMPA)	12.5%

Changes to Existing Resources

Retirements of generating units, system capacity uprates and derates, purchased power contract expirations, and adjustments in EE and DSM capability affect the amount of resources Duke Energy Carolinas will need to meet its load obligation. Thus, Duke Energy Carolinas will need to adjust the capabilities of its resource mix over the 20-year planning horizon. Below are the known and/or anticipated changes and their respective impacts on the resource mix.

New Cliffside Pulverized Coal Unit

Cliffside Unit 6 pulverized coal plant is expected to operate at 50-100% output for systems and equipment guarantee testing through the summer of 2012. The unit is expected to be declared commercial in September of 2012.

Bridgewater Hydro Powerhouse Upgrade

Bridgewater Hydro Station generating unit upgrades were operational November 2011. The previous generating units were replaced by two 15 MW units and a small 1.5 MW unit representing an 8.5 MW increase in station capability. The new generating units will be used to meet continuous release requirements and system peak.

Buck Combined Cycle Natural Gas Unit

The new Buck Combustion Turbine Combined Cycle (CTCC) unit was operational November 2011. The 620 MW natural gas-fired CTCC generating station achieves high operational flexibility, high thermal efficiency, utilizing state-of-the-art environmental control technology to minimize plant emissions.

Dan River Combined Cycle Natural Gas Unit

The 620 MW Dan River CC unit is scheduled to be operational by the end of 2012. Construction is underway and the project is currently over 90% complete.

Lee Steam Station Natural Gas Conversion

Lee Steam Station was originally designed to generate with natural gas or coal as a fuel source. Switching fuel sources from coal to natural gas could prove to be an economic solution to avoid adding costly pollution control equipment or replacing the 370 MW of capacity with a more costly alternative. Previous plans were for conversion of all three Lee units to natural gas. However upon further evaluation, for IRP planning purposes, Lee Units 1 and 2 will be retired as coal units with no plans for conversion to natural gas in 2015. Lee Unit 3 is assumed to be retired as a coal unit in the fourth quarter of 2014 and converted to natural gas by January 1, 2015. Preliminary engineering and analysis has been completed. Detailed project development and regulatory efforts began in 2011, and will continue into 2012.

Generating Units Projected To Be Retired

Various factors have an impact on decisions to retire existing generating units. These factors, including the investment requirements necessary to support ongoing operation of generation facilities, are continuously evaluated as future resource needs are considered. Table 5.D reflects current assessments of generating units with identified decision dates for retirement or major refurbishment.

There are two requirements related to the Company's retirement of 800 MWs of older coal units. The first, a condition set forth in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6, requires the retirement of the existing Cliffside Units 1-4 no later than the commercial operation date of the new unit, and retirement of older coal-fired generating units (in addition to Cliffside Units 1-4) on a MW-for-MW basis, considering the impact on the reliability of the system, to account for actual load reductions realized from the new EE and DSM programs up to the MW level added by the new Cliffside unit[3]. In addition to retiring Cliffside Units 1-4, the air permit for the new Cliffside unit requires the retirement of 350 MWs of older coal generation by 2015, a further 200 MWs by 2016, and an additional 250 MWs by 2018. If the NCUC determines that the scheduled retirement of any unit identified for retirement pursuant to the IRP will have a material adverse impact of the reliability of electric generating system, Duke Energy Carolinas may seek modification of this plan.

Additionally, multiple environmental regulatory issues are presently converging as the EPA has proposed new rules to regulate multiple areas relating to generation resources. These new rules, if implemented, will increase the need for the installation of additional control technology or retirement of coal fired generation in the 2014 to 2018 timeframe. Anticipating that there will be increased control requirements, the Carolinas 2012 IRP continues to include a planning assumption that all coal-fired generation that does not have an installed SO_2 scrubber will be retired in 2015.

Table 5.D shows the assumptions used for planning purposes rather than firm commitments concerning the specific units to be retired and/or their exact retirement dates. The conditions of the units are evaluated at least annually and decision dates are revised as appropriate. Duke Energy Carolinas will develop orderly retirement plans that consider the implementation, evaluation, and achievement of EE goals, system reliability considerations, long-term generation maintenance and capital spending plans, workforce allocations, long-term contracts including fuel supply and contractors, long-term transmission planning, and major site retirement activities.

[3] NCUC Docket No. E-7, Sub 790 Order Granting CPCN with Conditions, March 21, 2007.

<u>Table 5.D</u>
Projected Unit Retirements

STATION	CAPACITY IN MW	LOCATION	EXPECTED RETIREMENT	PLANT TYPE
Buck 3*	75	Salisbury, N.C.	RETIRED	Conventional Coal
Buck 4*	38	Salisbury, N.C.	RETIRED	Conventional Coal
Cliffside 1*	38	Cliffside, N.C.	RETIRED	Conventional Coal
Cliffside 2*	38	Cliffside, N.C.	RETIRED	Conventional Coal
Cliffside 3*	61	Cliffside, N.C.	RETIRED	Conventional Coal
Cliffside 4*	61	Cliffside, N.C.	RETIRED	Conventional Coal
Dan River 1*	67	Eden, N.C.	RETIRED	Conventional Coal
Dan River 2*	67	Eden, N.C.	RETIRED	Conventional Coal
Dan River 3*	142	Eden, N.C.	RETIRED	Conventional Coal
Buzzard Roost 6C**	22	Chappels, S.C.	10/1/2012	Combustion Turbine
Buzzard Roost 7C**	22	Chappels, S.C.	10/1/2012	Combustion Turbine
Buzzard Roost 8C**	22	Chappels, S.C.	10/1/2012	Combustion Turbine
Buzzard Roost 9C**	22	Chappels, S.C.	10/1/2012	Combustion Turbine
Buzzard Roost 10C**	18	Chappels, S.C.	10/1/2012	Combustion Turbine
Buzzard Roost 11C**	18	Chappels, S.C.	10/1/2012	Combustion Turbine
Buzzard Roost 12C**	18	Chappels, S.C.	10/1/2012	Combustion Turbine
Buzzard Roost 13C**	18	Chappels, S.C.	10/1/2012	Combustion Turbine
Buzzard Roost 14C**	18	Chappels, S.C.	10/1/2012	Combustion Turbine
Buzzard Roost 15C**	18	Chappels, S.C.	10/1/2012	Combustion Turbine
Riverbend 8C**	0	Mt. Holly, N.C.	10/1/2012	Combustion Turbine
Riverbend 9C**	22	Mt. Holly, N.C.	10/1/2012	Combustion Turbine
Riverbend 10C**	22	Mt. Holly, N.C.	10/1/2012	Combustion Turbine
Riverbend 11C**	20	Mt. Holly, N.C.	10/1/2012	Combustion Turbine
Buck 7C**	25	Spencer, N.C.	10/1/2012	Combustion Turbine
Buck 8C**	25	Spencer, N.C.	10/1/2012	Combustion Turbine
Buck 9C**	12	Spencer, N.C.	10/1/2012	Combustion Turbine
Dan River 4C**	0	Eden, N.C.	10/1/2012	Combustion Turbine
Dan River 5C**	24	Eden, N.C.	10/1/2012	Combustion Turbine
Dan River 6C**	24	Eden, N.C.	10/1/2012	Combustion Turbine
Riverbend 4*	94	Mt. Holly, N.C.	4/15/2015	Conventional Coal
Riverbend 5*	94	Mt. Holly, N.C.	4/15/2015	Conventional Coal
Riverbend 6***	133	Mt. Holly, N.C.	4/15/2015	Conventional Coal
Riverbend 7***	133	Mt. Holly, N.C.	4/15/2015	Conventional Coal
Buck 5***	128	Spencer, N.C.	4/15/2015	Conventional Coal
Buck 6***	128	Spencer, N.C.	4/15/2015	Conventional Coal
Lee 1***	100	Pelzer, S.C.	4/15/2015	Conventional Coal
Lee 2***	100	Pelzer, S.C.	4/15/2015	Conventional Coal
Lee 3****	170	Pelzer, S.C.	1/1/2015	Conventional Coal

Notes:

* Retirement assumptions associated with the conditions in the NCUC Order in Docket No. E-7, Sub 790, granting a CPCN to build Cliffside Unit 6.

** The old fleet combustion turbines retirement dates were accelerated in 2009 based on derates, availability of replacement parts and the general condition of the remaining units.

*** For the 2012 IRP process, remaining coal units without scrubbers were assumed to be retired by 4/15/2015. Based on the continued increased regulatory scrutiny from an air, water and waste perspective, these units will likely either be required to install additional controls or retire. If final regulations or new legislation allows for latitude in the retirement date if a retirement commitment is made, versus adding controls, the retirement date may be adjusted. For example, per the MATS rule, if new generation will be located at a retired facility site, the retirement of the existing facility may be extended to 4/15/2016.

**** Analysis has been performed to determine the feasibility of the conversion of the Lee 3 coal unit to a natural gas unit. As this project is further evaluated, this date is subject to change.

Fuel Supply

Duke Energy Carolinas' current fuel usage consists primarily of coal and uranium. Oil and gas have traditionally been used for peaking generation, but natural gas has begun to play a more important role in the fuel mix due to lower pricing and the addition of the Buck Combined Cycle plant. The addition of the Dan River Combined Cycle plant later this year will further increase the importance of gas to the Company's generation portfolio.

Coal

Until the economic downturn in 2008, Duke Energy Carolinas had burned approximately 18 million tons of coal annually. In 2009, the burn dropped substantially and has remained in the range of 14 to 16 million tons of coal. The projected coal burn for the near-term is declining further due to lower gas prices, the addition of the Buck CC plant, more stringent environmental regulations on coal units, and lower load growth.

The Company continues to procure coal primarily from Central Appalachian (CAPP) coal mines that is delivered by the Norfolk Southern and CSX railroads. Although CAPP coal market prices are currently below the marginal mining costs for many mines, due to this year's unseasonably mild winter and the resulting low gas prices, CAPP prices are projected to recover over the next couple of years. Longer term, CAPP prices are expected to rise due to a continuing decline in CAPP reserves quality, increasingly stringent safety requirements, and longer and increasingly difficult environmental permitting for CAPP mines.

For this reason, the Company has been testing Northern Appalachian (NAPP) and Illinois Basin (ILB) coals at its scrubbed stations. These tests will continue into the future and will provide valuable information on operational and environmental impacts of burning these coals in various blends. This information will assist the Company in determining which coal blends can be burned without requiring additional capital investment, as well as the capital investments required to consume even greater amounts of non-CAPP coal. The purpose of this work is not to lock the Company's plants into new fuel types, but to increase the fuel flexibility of each station so that the Company can nimbly respond to changes in the relative coal prices of different coal types.

Natural Gas

The issues affecting natural gas supply and demand are numerous and complex. An unusually warm winter has resulted in oversupply within the US gas market. Actions and reactions associated with attempts to bring this market into balance are projected to carry some long term consequences for the entire domestic energy industry. While the low market prices for gas have helped reduce industrial production costs, boost manufacturing output and demand for power, producers and pipelines are cutting back on investments in future gas drilling and redirecting capital to higher price margins in oil and petroleum liquids. Gas directed drillings rigs are down to 542, a ten-year low. In spite of the falling prices, the size of the economic reserve basis has increased due to significant gains in rig efficiency, improvements in wellhead productivity, and several other factors. Among these is the fact that gas is also being produced in the process of drilling for oil and liquids, drilling cost carries from asset sales, and a backlog of previously drilled but uncompleted wells that are holding gas supplies higher. Once again, the US is on course to set another record in total marketed US production of natural gas. These market responses have managed to stabilize the wholesale gas prices at around $2.50 - $3.00/mmbtu for now, and they are not likely to push prices significantly higher in the near term. Substantial producer discipline going forward or additional new sources of demand will be required to pull the higher marginal cost supplies back into this market.

The US shale boom was partially the result of innovation in the face of high marginal domestic gas prices and the threat of a future marked by a globally linked and high volatile liquefied natural gas (LNG) pricing. Today, the consensus view is that the US will enjoy a competitive price advantage over Asian and European competitors for the foreseeable future. This is driving massive energy investments. New or expanded industrial demand, calls for natural gas vehicle subsidies and fueling infrastructure, and preparations for exportation of LNG are coupled with critical decisions that have to be made in the US power industry. Utilities are making investment decisions today which will have lasting impacts on their generation fleets. They cannot simply defer these decisions either, as various environmental deadlines now loom large with 2015 EPA regulatory compliance dates. Given the relatively low pricing in the NYMEX forward curve and weak fundamentals, much of the coal displacement projections will soon become reality as utilities retire existing uncontrolled coal facilities instead of installing emissions controls. Natural gas has become the default option for new generation.

While the US has ample economic gas reserves for at least the next two decades, natural gas should still be viewed as a bridge fuel, rather than a final solution. The US will need to start addressing its nuclear end of life decisions within the next decade. This could put an enormous strain on US gas supplies if gas is the only replacement. New federal regulations are likely to be proposed in 2013 which will govern permitting, wastewater disposal and fugitive methane emissions. These regulations will add to the cost of gas production and should allow coal to recover some of its lost market share, but new regulations are unlikely to be so stringent that they become game changers. A significant price on carbon in the US has the potential to change the equation, but these indications are not currently on the horizon. Shale has already begun to reshape the US energy industry, but the currently low market prices will elicit changes in investment and demand that over time will pressure prices to move higher.

Nuclear Fuel

To provide fuel for Duke Energy Carolinas' nuclear fleet, the Company maintains a diversified portfolio of natural uranium and downstream services supply contracts from around the world.

Requirements for uranium concentrates, conversion services and enrichment services are primarily met through a portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. In addition, Duke Energy Carolinas staggers its contracting so that its portfolio of long-term contracts covers the majority of fleet fuel requirements in the near-term and decreasing portions of the fuel requirements over time thereafter. By staggering long-term contracts over time, the Company's purchase price for deliveries within a given year consists of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out the Company's exposure to price volatility. Diversifying fuel suppliers reduces the Company's exposure to possible disruptions from any single source of supply. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with spot market purchases.

Due to the technical complexities of changing suppliers of fuel fabrication services, Duke Energy Carolinas generally sources these services to a single domestic supplier on a plant-by-plant basis using multi-year contracts.

As fuel with a low cost basis is used and lower-priced legacy contracts are replaced with contracts at higher market prices, nuclear fuel expense is expected to increase in the future. Although the costs of certain components of nuclear fuel are expected to increase in future years, nuclear fuel costs on a kWh basis will likely continue to be a fraction of the kWh cost of fossil fuel. Therefore, customers will continue to benefit from the Company's diverse generation mix and the strong performance of its nuclear fleet through lower fuel costs than would otherwise result absent the significant contribution of nuclear generation to meeting customers' demands.

B. Renewable Resources and Renewable Energy Initiatives

1. Overview of Planning Assumptions

Duke Energy Carolinas' plans regarding renewable energy resources within this IRP are based primarily upon the presence of existing renewable energy requirements, as well as the potential introduction of additional renewable energy requirements in the future.

Regarding existing renewable requirements, the Company is committed to meeting the requirements of the NC REPS. This is a statutory requirement enacted in 2007 mandating that Duke Energy Carolinas supply the equivalent of 12.5% of retail electricity sales in North Carolina from eligible renewable energy resources and/or EE savings by 2021. NC REPS allows for compliance utilizing not only renewable energy resources supplying bundled energy and renewable energy certificates (RECs) and EE, but also the purchase of unbundled RECs (both in-state and out-of-state) and thermal RECs. Therefore, the actual energy delivered to the Duke Energy Carolinas system is impacted by the amount of EE, unbundled RECs and thermal RECs utilized for compliance.

With respect to potential new renewable energy portfolio standard requirements, the Company's plans in this IRP account for the possibility of future requirements that will result in additional renewable resource development beyond the NC REPS requirements. Renewable requirements have been adopted in many states across the nation, and have also been contemplated as a federal measure and by members of the General Assembly in South Carolina. As such, the Company believes it is reasonable to plan for additional renewable requirements within the IRP beyond what presently exists with the NC REPS requirements.

Although many reasonable assumptions could be made regarding such future renewable requirements, the Company has assumed for purposes of the 2012 IRP that a new legislative requirement (imposed by either federal or state level legislation) would be implemented in the future that would result in additional renewable resource development in South Carolina. For planning purposes, Duke Energy Carolinas has assumed that the requirement would be similar in many respects to the NC REPS requirement, but with a different implementation schedule. Specifically, the Company has assumed that this requirement would have an initial 3% milestone in 2016 and would gradually increase to a 12.5% level by 2025. Similar to NC REPS, this assumed legislative requirement would incorporate both renewable energy and EE, as well as a limited capability to utilize out of state unbundled purchases of RECs. Further, this assumed requirement would have a solar set-aside requirement comparable to that in NC REPS, but would not contain any additional set-asides such as the poultry waste or swine waste set-aside requirements that are part of NC REPS. Finally, no assumptions related to a cost-cap feature that may limit development of renewables and ultimate cost to customers were made with this assumed legislation, whereas the Company's projections of renewable resource development for NC REPS are governed by the statutory cost caps within the law.

The Company has assessed the current and potential future costs of renewable and traditional technologies and, based on this analysis, the IRP modeling process shows that, for the most part, the amount of renewable energy resources that will be developed over the planning horizon will be defined by the existing and anticipated statutory renewable energy requirements described above. In other words, the IRP modeling does not indicate any material quantity of renewable resource development over and above the required levels, unless incentivized with state and federal tax incentives. The increased level of QF solar facilities due to these incentives has been incorporated into the IRP modeling.

2. Summary of Expected Renewable Resource Capacity Additions

Based on the planning assumptions noted above regarding current and potential future renewable energy requirements, the Company projects that a total of approximately 970 MWs (nameplate) of renewable energy resources will be interconnected to the Duke Energy Carolinas system by 2021, with that figure growing to approximately 1,665 MWs by the end of the planning horizon in 2032. Actual results could vary substantially, with key drivers of different outcomes being future legislative requirements; relative costs of various renewable technologies in relation to traditional technologies; and various impediments impacting resource development, including permitting requirements, transmission and interconnection issues, or other matters.

It should be noted that many renewable technologies are intermittent in nature and that such resources therefore may not be contributing energy or capacity benefits to the Company's load requirements at any particular point in time. The details of the forecasted capacity additions, including both nameplate capacity and the expected contribution towards the Company's peak load needs, are summarized in Table 5.E below.

<u>Table 5.E</u> Expected Renewable Resource Capacity Additions

Renewables								
	MW Contribution to Summer Peak				MW Nameplate			
Year	Wind	Solar	Biomass	Total	Wind	Solar	Biomass	Total
2012	6	8	1	16	40	17	1	58
2013	0	28	10	38	0	56	10	66
2014	15	68	20	103	100	135	20	256
2015	15	127	30	171	100	253	30	383
2016	20	160	51	231	134	320	51	505
2017	20	176	60	256	135	352	60	546
2018	20	199	68	288	135	398	68	602
2019	48	235	90	374	322	471	90	883
2020	48	247	99	395	323	495	99	917
2021	49	269	108	426	324	538	108	970
2022	56	324	135	516	376	649	135	1160
2023	57	346	133	536	378	692	133	1204
2024	57	368	142	567	381	736	142	1258
2025	62	420	154	637	416	840	154	1411
2026	63	443	155	661	419	885	155	1459
2027	63	464	156	684	422	928	156	1507
2028	65	473	163	701	430	946	163	1540
2029	66	483	166	715	439	965	166	1571
2030	67	492	170	729	448	984	170	1602
2031	69	502	173	743	457	1004	173	1633
2032	69	502	173	758	457	1004	173	1665

3. Changes in Renewable Planning Assumptions Since 2011

The Company's assumptions relating to renewable energy requirements (existing and anticipated) included in the 2012 IRP are largely similar to the assumptions within the Company's 2011 IRP. However, the Company's expectations regarding how those requirements will be met have evolved. Changes from the prior year are summarized below.

As compared to last year's IRP, the Company has assumed the development and interconnection of more solar resources over the planning horizon, along with corresponding reductions in the development of wind and biomass resources.

The installed cost of solar resources has fallen dramatically over the past few years, driven by increased industry scale, standardization, and technological innovation. Many industry participants expect the cost of solar to continue a steady decline through the end of the decade, albeit at a slower pace than in recent years. Solar resources benefit from generous supportive federal and state policies that are expected to be in place through the middle of this decade or longer. In combination with declining costs, such supportive policies have made solar resources increasingly competitive with other renewable resources, including wind and biomass, at least in the near-term. While uncertainty remains around possible alterations or extensions of policy support, as well as the pace of future cost declines, the Company fully expects solar resources to contribute to our RPS compliance efforts beyond the solar set-aside minimum threshold for NC REPS, and correspondingly in SC.

The Company recognizes that several land-based wind developers are presently pursuing projects of significant size in North Carolina. The Company believes it is reasonable to expect that land-based wind will be developed in both North and South Carolina within the planning horizon. However, land-based wind in the US has benefitted from supportive federal tax policies set to decline at the end of 2012. Although the Company expects to rely upon wind resources for our RPS compliance effort, the extent and timing of that reliance will likely vary commensurately with changes to supporting policies and prevailing market prices. The Company also has observed that opportunities currently exist, and may continue to exist, to transmit land-based wind energy resources into the Carolinas from other regions, which could supplement the amount of wind that could be developed within the Carolinas.

The Company's expectations regarding biomass resources for the 2012 IRP are more modest than its assumptions within its prior two IRPs. Duke Energy Carolinas has reduced its reliance upon biomass resources in part due to continued uncertainties around the developable amount of such resources in the Carolinas, uncertainties related to the EPA's various rulemaking proceedings, and the projected availability of other forms of renewable resources to offset the needs for biomass.

The changes in the renewable strategy discussed above have an impact on the Company's projected resource need in the future. Even though solar facilities have a lower contribution to the Company's peak than biomass resources, the projected increase in volume of solar facilities results in a net increase of renewable resources available to meet peak demand requirements in 2015 of approximately 40 MW.

In general, the Company expects a mix of resources will ultimately be used for RPS compliance, with the specifics of that mix determined in large part by policy developments over the coming 5-10 years. Costs for all the resources discussed above are highly dependent upon future subsidies, or lack thereof, and the Company's procurement efforts will vary accordingly. Furthermore, the Company values portfolio diversification from a resource perspective, particularly in light of the varying load profiles of the resources in question.

4. Further Details on Compliance with NC REPS

A more detailed discussion of the Company's plans to comply with the NC REPS requirements can be found in the Company's NC REPS Compliance Plan (Compliance Plan), which the Company submits to the NCUC as a separate document within the same docket as this IRP.

Details of that Compliance Plan are not duplicated here, although it is important to note that various details of the NC REPS law have impacts on the amount of energy and capacity that the Company projects to obtain from renewable resources to help meet the Company's long term resource needs. For instance, NC REPS contains several detailed parameters, including technology specific set-aside requirements for solar, swine waste, and poultry waste resources; capabilities to utilize EE savings and unbundled REC purchases from in-state or out-of-state resources, and RECs derived from thermal (non-electrical) energy; and a statutory spending limit to protect customers from cost increases stemming from renewable energy procurement or development. Each of these features of NC REPS has implications on the amount of renewable energy and capacity the Company forecasts to obtain over the planning horizon of this IRP. Additional details on NC REPS compliance can be found in the Company's Compliance Plan.

C. Supply-Side Resource Screening

For purposes of the 2012 IRP, the Company considered a diverse range of technology choices utilizing a variety of different fuels, including supercritical pulverized coal (SCPC) units with carbon capture and sequestration (CCS), Integrated Gasification Combined Cycle (IGCC) with carbon capture and sequestration, combustion turbines (CTs), combined cycle (CC) with duct firing units, and nuclear units. In addition, Duke Energy Carolinas considered renewable technologies such as wind, landfill gas, and solar in this year's screening analysis.

For the 2012 IRP screening analyses, the Company screened technology types within their own respective general categories of base load, peaking/intermediate, and renewable, with the ultimate goal of screening to pass the best alternatives from each of these three categories to the integration process. As in past years, the reason for the initial screening analysis is to determine the most viable and cost-effective resources for further evaluation. This initial screening evaluation is necessary to narrow down options to be further evaluated in the quantitative analysis process.

1. Process Description

Information Sources

The cost and performance data for each technology being screened is based on research and information from several sources. These sources include, but may not be limited to the following: Duke Energy's New Generation Project Development, Emerging Technologies, and Analytical Engineering; the EPRI Technology Assessment Guide (TAG®); and studies performed by and/or information gathered from external sources. In addition, fuel and operating cost estimates are developed internally by Duke Energy, or from other sources such as those mentioned above, or a combination of the two. EPRI information or other information or estimates from external studies are not site-specific, but generally reflect the costs and operating parameters for installation in the Carolinas.

Finally, every effort is made to ensure that cost and other parameters are current and include similar scope across the technologies being screened. While this has always been important, keeping cost estimates across a variety of technology types consistent in today's markets for commodities, construction materials, and manufactured equipment, remains very difficult.

Technical Screening

The first step in the Company's supply-side screening process for the IRP is a technical screening of the technologies to eliminate those that have technical limitations, commercial availability issues, or are not feasible in the Duke Energy Carolinas service territory. A brief explanation of the technologies excluded at this point and the basis for their exclusion follows:

- Geothermal was eliminated because there are no suitable geothermal resources in the region to develop into a power generation project.

- Advanced energy storage technologies (Lead acid, Li-ion, Sodium Ion, Zinc Bromide, Fly wheels, pumped storage, etc) remain relatively expensive, as compared to conventional generation sources, but the benefits to a utility such as the ability to shift load and firm renewable generation are obvious. Research, development, and demonstration continue within Duke Energy Corporation (Duke Energy). Currently, Duke Energy Generation Services is installing a 36 MW advanced acid lead battery at the Notrees wind farm in Texas that is scheduled for start-up in late 2012. Duke Energy is also installing a 75 kW battery in Indiana which will be integrated with solar generation and electric vehicle charging stations. Duke Energy also has other storage system tests within its Envision Energy demonstration in Charlotte, which includes two Community Energy Storage (CES) systems of 24 kW, and three substation demonstrations less than 1 MW each.

- Compressed Air Energy Storage (CAES), although demonstrated on a utility scale and generally commercially available, is not a widely applied technology and remains relatively expensive. The high capital requirements for these resources arise from the fact that suitable sites that possess the proper geological formations and conditions necessary for the compressed air storage reservoir are relatively scarce.

- Small modular nuclear reactors (SMR) are generally defined as having capabilities of less than 300 MW. In 2012, U.S. Department of Energy (DOE) solicited bids for companies to participate in a small modular reactor grant program with the intent to "promote the accelerated commercialization of SMR technologies to help meet the nation's economic energy security and climate change objectives." The focus of the grant is the first-of-a-kind engineering associated with NRC design certification and licensing efforts in order to demonstrate the ability to achieve NRC design certification and licensing to support SMR plant deployment on a domestic site by 2022.

- Fuel Cells, although originally envisioned as being a competitor for combustion turbines and central power plants, are now targeted to mostly distributed power generation systems. The size of the distributed generation applications ranges from a few kW to tens of MW in the long-term. Cost and performance issues have generally limited their application to niche markets and/or subsidized installations. While a medium level of research and development continues, this technology is not commercially available for utility-scale application.

- Poultry waste and Swine waste digesters remain relatively expensive and are often faced with operational and/or permitting challenges. Research, development, and demonstration continue, but these technologies remain generally too expensive or face obstacles that make them impractical energy choices outside of specific mandates calling for use of these technologies.

- Off-shore wind, although demonstrated on a utility scale and commercially available, is not a widely applied technology and not easily permitted. This technology remains expensive and has yet to actually be constructed anywhere in the United States. Currently, the Cape Wind project in Massachusetts has been approved with assistance from the federal government but has not begun construction.

- Although commercially available, a 3x3x1 1200 MW natural gas combined cycle unit was modeled as sensitivity. The 2x2x1 700 MW combined cycle option more closely mirrored the resource needs for new generation in the near term. Review of the 3x3x1 combined cycle unit revealed that even though these units are efficient and cost-effective, the limits on operational flexibility outweighed the benefits of this unit. This unit will be considered in more detail in 2013.

Economic Screening

The supply-side screening analysis uses the same fuel prices for coal and natural gas, and NO_x, SO_2, and CO_2 allowance prices as those utilized downstream in the System Optimizer analysis (discussed in Chapter 8).

The Company screens all technologies using relative dollar per kilowatt-year ($/kW-yr) versus capacity factor screening curves. The screening within each general class, as well as the final screening across the general classes uses a spreadsheet-based screening curve model developed by Duke Energy. This model is considered proprietary, confidential and competitive information by Duke Energy.

This screening curve analysis model includes the total costs associated with owning and maintaining a technology type over its lifetime and computes a levelized $/kW-year value over a range of capacity factors.

The Company repeats this process for each supply technology to be screened resulting in a family of lines (curves). The lower envelope along the curves represents the least costly supply options for various capacity factors or unit utilizations. Some technologies have screening curves limited to their expected operating range on the individual graphs.

Lines that never become part of the lower envelope, or those that become part of the lower envelope only at capacity factors outside of their relevant operating ranges, have a very low probability of being part of the least cost solution, and generally can be eliminated from further analysis.

2. Screening Results

The results of the screening within each category are shown in Appendix C.

In the quantitative analysis phase, the Company further evaluates those technologies from each of the three general categories screened (Base load, Peaking/Intermediate, and Renewables) which had the lowest levelized busbar cost for a given capacity factor range within each of these categories.

While EPA's MATS and GHG New Source regulations may effectively preclude new coal-fired generation, Duke Energy Carolinas has included supercritical pulverized coal (SCPC) and integrated gasification combined cycle (IGCC) technologies with carbon capture sequestration (CCS) of 1000 pounds/net MWH and 800 pounds/net MWH as options for base load analysis consistent with the proposed EPA NSPS rules. Additional detail on the expected impacts from EPA regulations to new coal-fired options is included in Chapter 6.

With lower gas prices, larger capacities and increased efficiency, combined cycle units have become more cost-effective at higher capacity factors and have been included as a base load option.

The Company selected the following technologies for the quantitative analysis:

- Base load – 825 MW Supercritical Pulverized Coal with CCS
- Base load – 618 MW IGCC with CCS
- Base load – 2 x 1,117MW Nuclear units (AP1000)
- Base load – 700 MW – 2x2x1 Combined Cycle (Inlet Chiller and Fired)
- Peaking/Intermediate – 800 MW 4-7FA CTs
- Peaking/Intermediate – 600 MW 3-7FA CTs
- Peaking/Intermediate – 627 MW 8-7EA CTs
- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Landfill Gas
- Renewable – 25 MW Solar PV

3. Unit Size

The unit sizes selected for planning purposes generally are the larger technologies available today because they generally offer lower $/kW installed capital costs due to economies of scale. However, the true test of whether a resource is economical depends on the economics of an overall resource plan that contains all costs associated with that resource (fuel costs, O&M costs, emission costs, etc.), not merely on the capital $/kW cost. In the case of very large unit sizes such as those utilized for the nuclear and/or IGCC technology types, if these are routinely selected as part of a least cost plan, joint ownership can and may be evaluated and pursued.

4. Cost, Availability, and Performance Uncertainty

Supply-side alternative project scope and estimated costs used for planning purposes for conventional technology types, such as simple-cycle CT units and CC units, are relatively well-known and are estimated in the TAG® and may be obtained from architect and engineering (A&E) firms and/or equipment vendors. The Company also uses its experience with the scope and costs for such resources to confirm the reasonableness of the estimates. The cost estimates include step-up transformers and a substation to connect with the transmission system. Since any additional transmission costs would be site-specific and specific sites are unknown at this time, typical values for additional transmission costs were also added to the alternatives. For natural gas units, gas pipeline costs were also included in the cost estimates. The unit availability and performance of conventional supply-side options are also relatively well-known and the TAG®, A&E firms and/or equipment vendors are sources of estimates of these parameters.

5. Lead Time for Construction

The estimated lead time for construction and permitting for modeling purposes for the proposed simple-cycle CT and combined cycle units is four to five years. For coal units, the lead time is assumed to be longer, approximately five to six years. For nuclear units, the lead time is assumed to be twelve to thirteen years or longer. However, the time required to obtain regulatory approvals and environmental permits adds uncertainty to the process, so Company judgment is incorporated into the analysis, as necessary.

6. RD&D Efforts and Technology Advances

New energy and technology alternatives will be necessary to ensure a long-term sustainable electric future. Duke Energy Carolinas' research, development, and delivery (RD&D) activities enable Duke Energy Carolinas to track new options including small modular nuclear reactors, advanced CTs, advanced fossil technologies, distributed energy sources, and energy storage technologies. To assure a strategic advantage in electricity supply and delivery, the Company places emphasis on providing information, assessment tools, validated technology, demonstration/deployment support, and RD&D investment opportunities for planning and implementing projects utilizing new power generation technology.

Within the planning horizon of this forecast, Duke Energy Carolinas expects that significant advances will continue to be made in CT technology. Advances in stationary industrial CT technology should result from ongoing research and development efforts to improve both commercial and military aircraft engine efficiency and power density, as well as expanding research efforts to burn more hydrogen-rich fuels derived from the IGCC process. The ability to burn hydrogen-rich fuels will enable very high levels of CO_2 removal, thereby enabling a major portion of the advancement necessary for a significant reduction in the carbon footprint of this coal-based technology.

Duke Energy Carolinas is evaluating more natural gas-fueled new generation because of the increase in available fuel sources, such as shale gas. Despite the lower greenhouse gas emission impact of natural gas-fired generation, carbon capture remains an issue when utilized in conjunction with natural gas resources. Most recent studies of carbon capture have been focused on coal-fired generation, as opposed to natural gas generation.

Duke Energy Carolinas' research and development groups have been evaluating various means of capturing carbon from natural gas fired generation through post-combustion capture and oxy-fuel combustion technologies. Through its partnerships with governmental agencies, non-governmental agencies, academia, and other companies, Duke Energy Carolinas is evaluating the technical and economic impacts of adding such systems to its existing and future generation. With the increased focus on natural gas generation, it is anticipated that a greater focus will be placed on natural gas carbon capture technology.

7. Coordination with Other Utilities

Decisions concerning coordinating the construction and operation of new units with other utilities or entities are dependent on a number of factors including the size of the unit versus each utility's capacity requirement and whether the timing of the need for facilities is the same. To the extent that units larger than Duke Energy Carolinas' needs become economically viable as part of a plan, co-ownership can be considered at that time. Coordination with other utilities can also be achieved through purchases and sales in the bulk power market.

D. Wholesale and QF Purchased Power Agreements

Duke Energy Carolinas is an active participant in the wholesale market for capacity and energy. The Company has issued RFPs for purchased power capacity in the past, and has entered into purchased power arrangements for over 2,000 MWs over the past 10 years. In addition, Duke Energy Carolinas has contracts with a growing number of Qualifying Facilities (QF or QFs). Table 5.F shows both the purchased power capacity obtained through RFPs, as well as the larger QF agreements. There are numerous contracts in various stages of negotiation and contracting, and the listing is constantly changing. Table 5.F is intended to represent only a snapshot of signed contracts as of August 1, 2012. See Appendix I for additional information on purchases from QFs.

Table 5.F
Wholesale Purchase & Purchased Power Commitments

SUPPLIER	CITY	STATE	SUMMER FIRM CAPACITY (MW)	WINTER FIRM CAPACITY (MW)	CONTRACT START	CONTRACT EXPIRATION
Cargill Power Marketing	Various Counties	ND / SD	6	6	1/1/2012	1 year
Catawba County	Newton	NC	3.7	3.7	8/23/1999	8/22/2014
Cherokee County Cogeneration Partners, L.P.	Gaffney	SC	88	88	7/1/1996	6/30/2013
Concord Energy, LLC	Concord	NC	9.2	9.2	2/5/2012	12/31/2031
Davidson Gas Producers, LLC	Lexington	NC	1.6	1.6	12/1/2010	12/31/2030
Gas Recovery Systems, LLC	Concord	NC	3	4	2/1/2010	12/31/2030
Gaston County	Dallas	NC	3.2	3.2	3/31/2011	12/31/2021
Greenville Gas Producers, LLC	Greer	SC	3.2	3.2	8/1/2008	Ongoing
Lockhart Power Company	Wellford	SC	1.6	1.6	4/1/2011	12/31/2020
MP Durham, LLC	Durham	NC	3.2	3.2	9/18/2009	12/31/2029
Northbrook Carolina Hydro, LLC	Various	NC & SC	5.9	5.9	12/4/2006	Ongoing
Salem Energy Systems, LLC	Winston-Salem	NC	4.3	4.3	7/10/1996	Ongoing
SunEd DEC1, LLC	Lexington	NC	7.8	7.8	12/1/2009	12/31/2030
Town of Lake Lure	Lake Lure	NC	2.5	2.5	2/21/2006	2/20/2011
WMRE Energy, LLC	Kernersville	NC	2.4	2.4	3/31/2011	12/31/2026
Misc. Small PV*	Various	NC & SC	8.2	8.2	Various	Various
Misc. Small Hydro/Other	Various	NC & SC	6.4	6.5	Various	Assumed Evergreen

Summary of Wholesale Purchased Power Commitments
(as of August 1, 2012)

	SUMMER 2012
Non-Utility Generation	
Traditional	109 MW
Renewable *	73MW
Duke Energy Carolinas allocation	
of SEPA capacity	8 MW
Other-Wholesale	107.2 MW
Total Firm Purchases	297.2 MW

Planning Philosophy with Regard to Purchased Power

Opportunities for the purchase of wholesale power from suppliers and marketers are an important resource option for meeting the electricity needs of Duke Energy Carolinas' retail and wholesale customers. Duke Energy Carolinas has been active in the wholesale purchased power market and has entered into contracts totaling approximately 2500 MWs since 2001 to meet customer needs. The use of supply side requests for proposal (RFPs) continues to be an essential component of Duke Energy Carolinas' resource procurement strategy. In particular, the purchased power agreements that the Company has entered into have allowed customers to enjoy the benefits of discounted market capacity prices and have provided flexibility in meeting target planning reserve margin requirements.

The Company's approach to resource selection is as follows:

The IRP process is used to identify the type, size, and timing of the resource need. In selecting the optimal resource plan, Duke Energy Carolinas begins with an optimization model that selects the resource mix that minimizes the present value of revenue requirements (PVRR) for a given set of assumptions. The levelized cost method used for generation options serves as a proxy for either self-build or long-term purchased power opportunities. From the optimization step, several diverse portfolios of resources are selected for further detailed production cost modeling and ultimate selection of a resource plan for the IRP.

Once a resource need is identified, the Company determines the options to satisfy that need and determines the near-term and long-term actions necessary to secure the resource. The options could include a self-build Duke Energy Carolinas-owned resource, a Duke Energy Carolinas-owned acquired resource (new or existing), or a purchased power resource. The Company consistently has issued RFPs for peaking and intermediate resource needs. For example, following the identification of peaking and intermediate resource needs, the Company issued a RFP in May 2007 for conventional intermediate and peaking resource proposals of up to 800 MW beginning in the 2009-2010 timeframe and up to 2000 additional MW beginning in the 2013 timeframe. Potential bidders could submit bids for purchased power or for the acquisition of existing or new facilities. Ten bidders submitted a total of forty-five bids spanning time periods of two to thirty years. The bid evaluation considered price, operational flexibility, and location benefits. Ultimately, the Company determined that none of the proposed bids provided sufficient advantages to offset the multiple benefits of the proposed Buck and Dan River CC projects. The consideration of purchased power options was described in the Company's CPCN application for these facilities and addressed in testimony. The NCUC issued the CPCNs for the Buck and Dan River CC projects in June 2008.

The Company also issued an RFP for renewable energy proposals in 2007. This RFP process produced proposals for approximately 1,900 megawatts of electricity from alternative sources from 26 different companies. The bids included wind, solar, biomass, biodiesel, landfill gas, hydro, and biogas projects. The Company entered into PPAs for a large solar project and several landfill gas facilities. In addition, the Company continues to receive unsolicited proposals for renewable purchased power resources and has entered into several PPAs as a result of unsolicited proposals.

The 2012 IRP plan includes approximately 2,100 MWs of new CC capacity, 1,800 MWs of new CT capacity, in addition to existing and committed resources for the Cliffside Modernization project and Buck and Dan River combined cycle projects, as well as new nuclear generation. The new CC resources meet an identified need for intermediate/base load capacity, whereas the new CT resources meet an identified need for peaking capacity. However, new CCs as an intermediate/base load resource remains uncertain as the capacity factor of these units are highly dependent on the price of natural gas and carbon legislation assumptions. Even though CC is projected to operate in a base load capacity in the near-term, by 2016, the units are projected to operate in a more intermediate manner. These needs will be refined in future IRPs and could be met through new self-build capacity, purchased power, additional DSM or any combination of the three.

Although Duke Energy Carolinas evaluates the competitive wholesale market for peaking and intermediate resources, the Company's purchased power philosophy does not currently include soliciting purchased power bids for base load capacity. Duke Energy Carolinas views base load capacity as fundamentally different from peaking and intermediate capacity. Currently, there are two key concerns with relying upon the wholesale market for base load capacity. First, generation outside the control area could be subject to interruption due to transmission issues more so than generation within the control area. Second, supplier default could jeopardize the ability to provide reliable service. The Company therefore believes that Duke Energy Carolinas-owned base load resources are the most reliable means for Duke Energy Carolinas to meet its service obligations in a cost-effective and reliable manner.

In addition, the Company examines unsolicited bids for purchased power or resource acquisitions and is alert to opportunities to purchase power or resources.

6. ENVIRONMENTAL COMPLIANCE

Legislative and Regulatory Issues

Duke Energy Carolinas, which is subject to the jurisdiction of federal agencies including the Federal Energy Regulatory Commission (FERC), EPA, and the NRC, as well as state commissions and agencies, is potentially impacted by state and federal legislative and regulatory actions. This section provides a high-level description of several issues Duke Energy Carolinas is actively monitoring or engaged in that could potentially influence the Company's existing generation portfolio and choices for new generation resources.

Air Quality

Duke Energy Carolinas is required to comply with numerous state and federal air emission regulations, including the current Clean Air Interstate Rule (CAIR) NO_x and SO_2 cap-and-trade program, and the 2002 North Carolina Clean Smokestacks Act (NC CSA).

As a result of complying with the NC CSA, Duke Energy Carolinas will reduce SO_2 emissions by approximately 75% by 2013 from 2000 levels. The law also required additional reductions in NO_x emissions in 2007 and 2009, beyond those required by the CAIR rule, which Duke Energy Carolinas has achieved. This landmark legislation, which was passed by the North Carolina General Assembly in June of 2002, calls for some of the lowest state-mandated emission levels in the nation, and was passed with Duke Energy Carolinas' input and support.

The following Charts 6.A and 6.B show Duke Energy Carolinas' NO_x and SO_2 emissions reductions to comply with the 2002 NC CSA requirements and actual emissions through 2011.

Chart 6.A

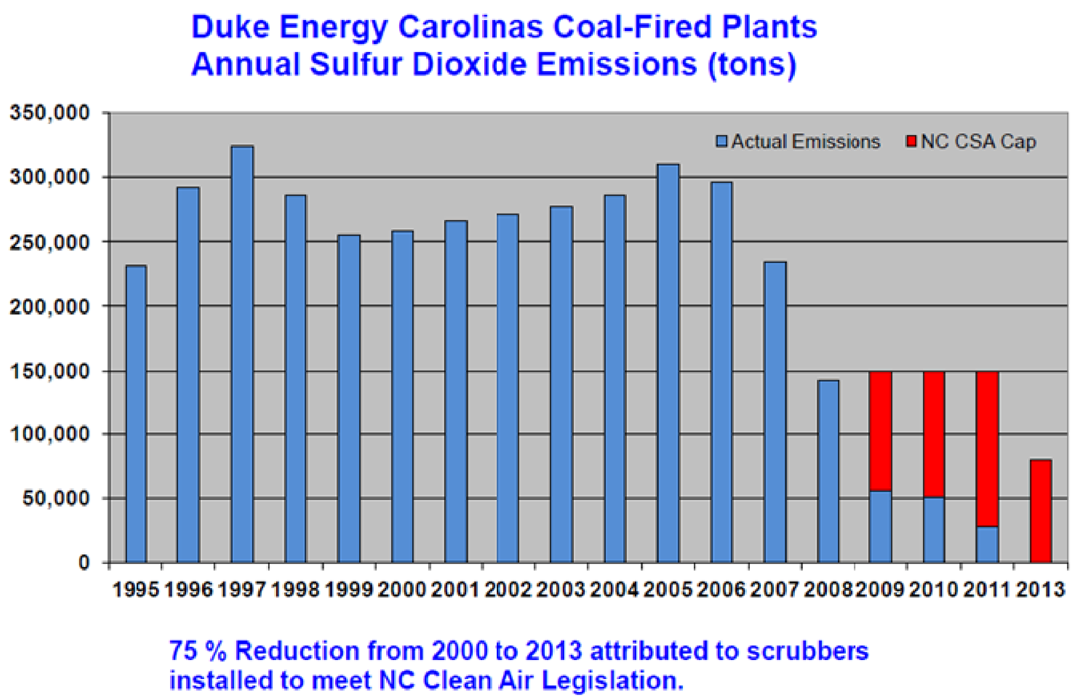
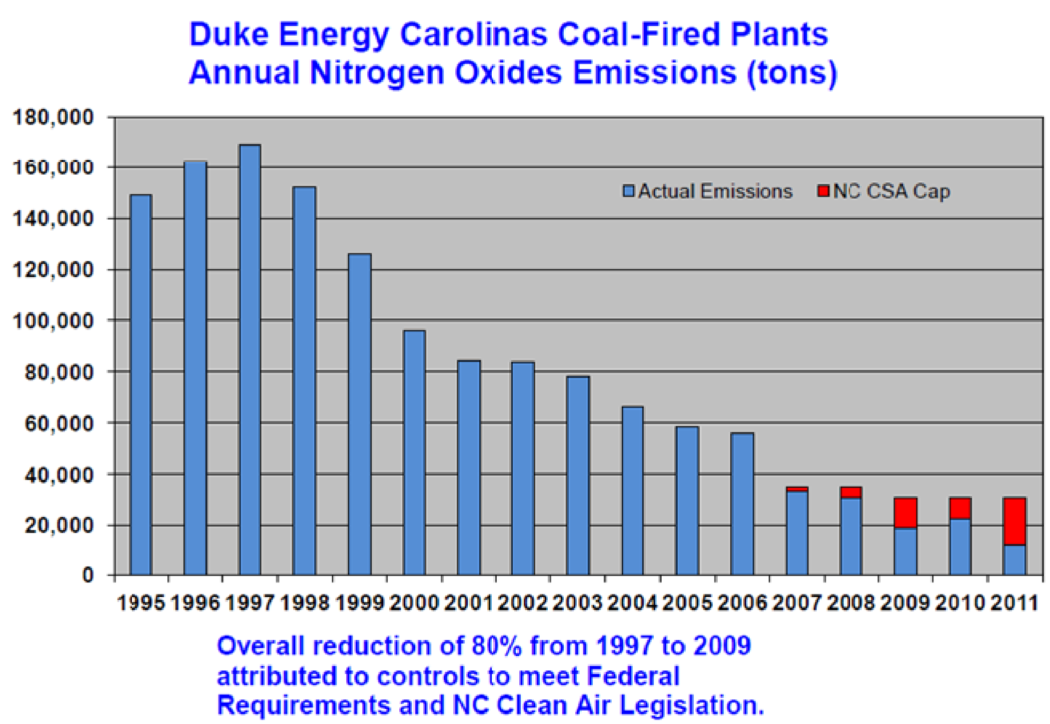


Chart 6.B



In addition to current programs and regulatory requirements, several new regulations are in various stages of implementation and development that will impact operations for Duke Energy Carolinas in the coming years. Some of the major rules include:

Cross-State Air Pollution Rule and the Clean Air Interstate Rule (CAIR)

The EPA finalized its CAIR in May 2005. The CAIR limits total annual and summertime NO_x emissions and annual SO_2 emissions from electric generating facilities across the Eastern U.S. through a two-phased cap-and-trade program. Phase 1 began in 2009 for NO_x and in 2010 for SO_2. Phase 2 of CAIR would begin in 2015. In July 2008, the U.S. Court of Appeals for the District of Columbia (D.C. Circuit) issued its decision in *North Carolina v. EPA* vacating the CAIR. In December 2008, the D.C. Circuit issued a decision remanding the CAIR to the EPA, allowing CAIR to remain in effect until EPA develops new regulations.

In August 2010, EPA published a proposed replacement rule for CAIR, known as the Transport Rule (TR). The rule was finalized as the Cross-State Air Pollution Rule (CSAPR) on July 6, 2011. The CSAPR, which establishes state-level annual SO_2 and NO_X budgets and ozone-season NO_X budgets was to take effect on January 1, 2012; however on December 30, 2011 the rule was stayed by the U.S. Court of Appeals for the DC Circuit. Oral arguments on the rule occurred in April 2012 and on August 21, 2012, the court ruled to vacate the CSAPR. In the opinion, the court holds that the CSAPR exceeds EPA's statutory authority and directs EPA to continue administering the CAIR pending completion of a remand rulemaking to replace CSAPR with a valid rule. At this time, there is no schedule for when a new replacement rule may occur, however, if the court decision were reversed on appeal, the earliest CSAPR could likely be implemented in 2015.

Duke Energy Carolinas will continue to implement and comply with CAIR. No significant impacts are expected for Duke Energy Carolinas' continued compliance with CAIR.

Mercury and Air Toxics Standard (MATS)

In May 2005, the EPA issued the Clean Air Mercury Rule (CAMR). The rule established mercury emission-rate limits for new coal-fired steam generating units, as defined in Clean Air Act (CAA) section 111(d). It also established a nationwide mercury cap-and-trade program covering existing and new coal-fired power units.

In February 2008, the D.C. Circuit Court of Appeals issued its opinion, vacating the CAMR. EPA announced a proposed Utility Boiler Maximum Achievable Control

Technology (MACT) rule in March 2011 to replace the CAMR. The EPA published the final rule, known as the Mercury and Air Toxics Standard (MATS), in the Federal Register on February 16, 2012. MATS regulates Hazardous Air Pollutants (HAP) and establishes unit-level emission limits for mercury, acid gases, and non-mercury metals as well as organics standards for coal and oil-fired electric generating units. Compliance with the emission limits will be required within three years of the effective date of the rule (April 16, 2012). The rule gives permitting authorities the discretion to grant up to a 1-year compliance extension, on a case-by-case basis, for sources that are unable to install emission controls before the compliance deadline. The one-year extension to meet compliance is not to be granted for units set to retire, unless replacement generation is located at the site.

Based on the emission limits established by the MATS rule, the Company expects its compliance with the MATS rule to drive the retirement of several non-scrubbed facilities in the Carolinas, as well as various changes to units that have been modified over the last several years, to meet the emission requirements of the NC CSA.

In addition to the limits imposed by the MATS rule on Duke Energy Carolinas' existing power plants, the rule also establishes emissions standards for any new pulverized coal or IGCC power plant that may start construction in the future. The emission limits established for any new pulverized coal plant are significantly more stringent than those imposed on the existing power plant fleet. Thus, future construction of pulverized coal units would not currently be considered technologically feasible relative to MATS compliance. On July 20, 2012, EPA did announce plans to reconsider certain new source issues with the MATS rule. This reconsideration rulemaking is expected to be completed by March of 2013.

National Ambient Air Quality Standards (NAAQS)

8 Hour Ozone Standard

In March 2008 EPA revised the 8-hour ozone standard by lowering it from 84 to 75 parts per billion (ppb). In September 2009, EPA announced a decision to reconsider the 75 ppb standard. The decision was in response to a court challenge from environmental groups and EPA's belief that a lower standard was justified. However, after much debate, EPA announced in September 2011 that it would retain the 75 ppb primary standard until it is reconsidered under the next 5-year review, which is expected to be proposed in October 2013 and finalized in July 2014 (possibly in the 60 to 70 ppb range). The earliest attainment date for a standard revised in 2014 would likely be 2019, and would depend on a nonattainment area's classification.

On April 30, 2012 EPA finalized the area designations for the 2008 75 ppb 8-hour ozone standard. The Charlotte area is now classified as a “marginal” nonattainment area, which establishes December 31, 2015 as its attainment date. For marginal nonattainment areas, states are not required to prepare an attainment demonstration. EPA in its final rule states that it performed an analysis that indicates that the majority of areas classified as marginal will be able to attain the 75 ppb standard in 2015 due to federal and state emission reduction programs already in place. If the Charlotte area’s 2013-2015 air quality does not qualify it to be reclassified as attainment, the area can still qualify for the first of two possible one-year extensions of the attainment date if it has no more than one exceedance of the standard in 2015. Alternatively, should the Charlotte area not attain the standard by its attainment date and thus not qualify for an extension, it will be bumped up to the next higher classification. For Charlotte, this would be moderate, which would then establish a 6-year attainment schedule and require NC to develop an attainment SIP.

SO_2 Standards

In November 2009, EPA proposed a rule to replace the 24-hour and annual primary SO_2 NAAQS with a 1-hour SO_2 standard. EPA finalized its new 1-hr standard of 75 ppb in June 2010. The SO_2 NAAQS designation process is different from all previous NAAQS in that EPA will not designate an area as attainment based solely on monitored air quality data. To support a recommended designation of attainment the state must also have dispersion modeling of major SO_2 sources at their potential-to-emit rate that shows no violation of the standard. In the absence of such modeling, areas with monitored clean air and areas without a monitor will be designated unclassifiable. EPA plans to designate an area as nonattainment if it has monitoring data or modeling results showing a violation of the standard.

However, in a letter dated April 12, 2012, EPA announced that it would not require modeling as part of the states’ June 2013 SIP submissions for unclassifiable areas. EPA further said that it would convene stakeholder outreach on modeling and that afterwards it expects to outline further SIP requirements in a future rulemaking process. Oral arguments were heard on May 3, 2012 in the DC Circuit Court. The court focused on whether EPA’s modeling-based implementation approach is final agency action subject to challenge, especially in light of EPA’s April 12 letters. On July 20, 2012, the Court upheld the EPA’s 1-hour SO_2 NAAQS and at the same time ruled that EPA statements in the preamble of the final rule regarding the use of modeling are not final agency action and are therefore not reviewable by the court. The court indicated that petitioners can challenge the use of modeling if or when EPA takes final action that imposes an obligation that petitioners must meet.

It remains unclear whether EPA will require states to perform source-specific modeling of major SO_2 emission sources (greater than 100 TPY) in unclassifiable areas to either demonstrate that a source is not causing or contributing to an exceedance of the standard or if it does, to determine the amount of emission reduction necessary to eliminate the modeled exceedance. Should modeling not be required for unclassifiable areas, the risk for additional SO_2 reductions or permit changes at Carolinas stations would likely be reduced. EPA is delaying final designations for most areas until June 2013. As such, the Company estimates any required controls could need to be in place sometime in 2017. A major SO_2 source located in a designated nonattainment area would most likely be modeled by the state and therefore could be at a high risk of being required to lower emissions if the modeling shows an exceedance of the 1-hour standard.

In addition, EPA is proposing to require states to relocate some existing monitors and to add new monitors. While these monitors will not be used by EPA to make the initial nonattainment designations, they will play a role in identifying possible future nonattainment areas.

Particulate Matter (PM) Standard

In September 2006, the EPA announced its decision to revise the $PM_{2.5}$ NAAQS standard. The daily standard was reduced from 65 ug/m^3 (micrograms per cubic meter) to 35 ug/m^3. The annual standard remained at 15 ug/m^3.

EPA finalized designations for the 2006 daily standard in October 2009, which did not include any nonattainment areas in the Duke Energy Carolinas service territory. In February 2009, the D.C Circuit unanimously remanded to EPA the Agency's decision to retain the annual 15 ug/m^3 primary $PM_{2.5}$ NAAQS and to equate the secondary $PM_{2.5}$ NAAQS with the primary NAAQS. EPA began undertaking new rulemaking to revise the standards consistent with the Court's decision. The current annual and daily $PM_{2.5}$ standards alone are not driving any emission reductions at Duke Energy Carolinas facilities. The reduction in SO_2 and NO_x emissions to address the current annual standard are being addressed through CAIR. Reductions to address the current daily standard will be addressed as part of the CSAPR, when implemented (the CSAPR will continue to address reductions needed for the current annual standard).

On June 14, 2012, the EPA proposed to lower the current 15 ug/m^3 $PM_{2.5}$ annual standard to a level within the range of 12 ug/m^3 to 13 ug/m^3. The EPA plans to finalize a new annual standard by December 2012, and finalize area designations by December 2014. States with nonattainment areas will be required to submit SIPs to EPA in early 2018, with the initial attainment date in 2020. The EPA has indicated that it will likely use 2011 – 2013 air quality data to make final designations, which could show improved air quality compared to current data. It is unclear if the lower standard will trigger the EPA to develop a new transport rule. If EPA were to do so, such a rule could result in a requirement for reduced SO_2 and/or NO_x emissions at Carolinas generating units. The potential timing of such a rulemaking is uncertain.

Greenhouse Gas Regulation

The EPA has been active in the regulation of greenhouse gases (GHGs). In May 2010, the EPA finalized what is commonly referred to as the Tailoring Rule, which sets the emission thresholds to 75,000 tons/year of CO_2 for determining when a source is potentially subject to Prevention of Significant Deterioration (PSD) permitting for GHGs. The Tailoring Rule went into effect beginning January 2, 2011. Being subject to PSD permitting requirements for CO_2 will require a Best Available Control Technology (BACT) analysis and the application of BACT for GHGs. BACT will be determined by the state permitting authority. Since it is not known if, or when, a Duke Energy Carolinas generating unit might undertake a modification that triggers PSD permitting requirements for GHGs and exactly what might constitute BACT at a particular point in time, the potential implications of this regulatory requirement are presently unknown. In addition, EPA announced in July 2011 that it was undertaking a three year study of CO_2 emissions from stationary bio-energy sources. This study is expected to yield a determination regarding the use of biomass as a carbon neutral source of generation and its potential use as BACT.

On April 13, 2012, the EPA proposed new rules to establish GHG new source performance standards (NSPS) for new electric utility steam generating units (EGUs). The proposed GHG NSPS applies only to new pulverized coal, IGCC and natural gas combined cycle units. The proposed NSPS is an output-based emission standard of 1,000 lb CO_2/gross MWh of electricity generation. At the present, carbon capture and storage (CCS) is the only technology capable of attaining this standard on pulverized coal or IGCC units. However, new pulverized coal and IGCC with CCS are currently not economically competitive technologies as new generation options. In addition, the geology in the Carolinas is not conducive to the sequestration of $CO_{2.}$ With respect to new natural gas combined cycle facilities, the proposed standard will not require the installation of CCS technology.

The proposal excludes new simple cycle turbines from the regulation. EPA is not proposing an emission standard for NSPS modified or reconstructed units. EPA states in the proposal that its current definition of an NSPS modification specifically exempts pollution control projects on an existing unit (for example, projects to comply with MATS or CSAPR). EPA has not given any indication when it might propose a GHG NSPS rule for existing sources.

It is currently not known if or when any federal climate change legislation limiting GHG emissions might be enacted.

Water Quality and By-product Issues

CWA 316(b) Cooling Water Intake Structures

Federal regulations in Section 316(b) of the Clean Water Act may necessitate cooling water intake modifications and/or cooling towers for existing facilities to minimize impingement and entrainment of aquatic organisms. All Duke Energy Carolina's coal and nuclear generating stations are potentially affected sources under that rule.

EPA issued a proposed rule on April 20, 2011 and is expected to finalize the rule by June 2013. Depending upon a station's National Pollutant Discharge Elimination System (NPDES) permit renewal schedule, compliance with the rule could begin as early as 2016.

EPA's proposed rule lists four options with a preference for one option. The preferred option impacts all facilities with a design intake flow greater than 2 million gallons per day (mgd) from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters that utilize at least 25% of the water withdrawn for cooling purposes. In order to meet fish impingement standards, intake screen modifications are likely to be needed for nearly all plant intakes. EPA has not mandated the use of cooling towers as "Best Technology Available" to address entrainment requirements. However, site specific studies are proposed by the rule in order to address best technology options for complying with the entrainment requirements. These studies could begin as early as late 2013.

Steam Electric Effluent Guidelines

In September 2009, EPA announced plans to revise the steam electric effluent guidelines. The regulation is to be technology-based, in that limits are based on the capability of technology. The primary focus of the revised regulation is on coal-fired generation, thus the major areas likely to be impacted are FGD wastewater treatment systems and ash handling systems. The EPA may set limits that dictate certain FGD wastewater treatment technologies for the industry and may require dry ash handling systems be installed.

According to a joint stipulation filed by EPA and environmental groups on April 3, 2012, EPA now plans to issue a draft rule by November 20, 2012 and a final rule by April 28, 2014. After the final rulemaking, effluent guideline requirements will be included in a station's NPDES permit renewals. Thus, requirements to comply with NPDES permit conditions may begin as early as 2017 for some facilities. The length of time allowed to comply will be determined through the permit renewal process. Steam electric effluent guidelines may also revise thermal discharge requirements.

Coal Combustion Residuals

Following Tennessee Valley Authority's Kingston ash dike failure in December 2008, EPA began an effort to assess the integrity of ash dikes nationwide and to develop a rule to manage coal combustion residuals (CCRs). CCRs include fly ash, bottom ash and FGD byproducts (gypsum). Since the 2008 dike failure, numerous ash dike inspections have been completed by EPA and an enormous amount of input has been received by EPA, as it developed proposed regulations.

In June 2010, EPA issued its proposed rule regarding CCRs. The proposed rule offers two options: (1) a hazardous waste classification under Resource Conservation and Recovery Act (RCRA) Subtitle C; and (2) a non-hazardous waste classification under RCRA Subtitle D, along with dam safety and alternative rules. Both options would require strict new requirements regarding the handling, disposal and potential re-use ability of CCRs. The proposal could result in more conversions to dry handling of ash, more landfills, closure of existing ash ponds and the addition of new wastewater treatment systems. Final regulations are not expected until sometime in 2013 or later. EPA's regulatory classification of CCRs as hazardous or non-hazardous will be critical in developing plans for handling CCRs in the future. The impact to Duke Energy Carolinas of this regulation as proposed is likely to be significant. The schedule for compliance will depend upon when EPA finalizes a rule, but is currently anticipated in the 2018 – 2021 timeframe.

7. TRANSMISSION AND DISTRIBUTION

A. Transmission System Adequacy

Duke Energy Carolinas monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks 10 years ahead at available generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. The Duke Energy Carolinas' transmission model is incorporated into models used by regional reliability groups in developing plans to maintain interconnected transmission system reliability. Duke Energy Carolinas works with PEC, NCEMC and ElectriCities to develop an annual NC Transmission Planning Collaborative (NCTPC) plan for the Duke Energy Carolinas and PEC systems in both North and South Carolina. In addition, transmission planning is coordinated with neighboring systems including South Carolina Electric & Gas (SCE&G) and Santee Cooper under a number of mechanisms including legacy interchange agreements between SCE&G, Santee Cooper, PEC, and Duke Energy Carolinas.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with Duke Energy Carolinas' Transmission Planning Guidelines for voltage and thermal loading. The annual screening uses methods that comply with SERC policy and NERC Reliability Standards and the screening results identify the need for future transmission system expansion and upgrades and are used as inputs into the Duke Energy Carolinas – Power Delivery optimization process. The Power Delivery optimization process evaluates problem-solution alternatives and their respective priority, scope, cost, and timing. The optimization process enables Power Delivery to produce a multi-year work plan and budget to fund a portfolio of projects which provides the greatest benefit for the dollars invested.

Duke Energy Carolinas currently evaluates all transmission reservation requests for impact on transfer capability, as well as compliance with the Company's Transmission Planning Guidelines and the FERC Open Access Transmission Tariff (OATT). The Company performs studies to ensure transfer capability is acceptable to meet reliability needs and customers' expected use of the transmission system. The Power Delivery optimization process is also used to manage projects for improvement of transfer capability.

SERC audits Duke Energy Carolinas every three years for compliance with NERC Reliability Standards. Specifically, the audit requires Duke Energy Carolinas to demonstrate that its transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications. SERC conducted a NERC Reliability Standards compliance audit of Duke Energy Carolinas in May 2011. The scope of this audit included Transmission Planning Standards TPL-002-0.a and TPL-003-0a. For both Standards, Duke Energy Carolinas received "No Findings" from the audit team.

Duke Energy Carolinas participates in a number of regional reliability groups to coordinate analysis of regional, sub-regional and inter-control area transfer capability and interconnection reliability. The reliability groups' purpose is to:

- Assess the interconnected system's capability to handle large firm and non-firm transactions for purposes of economic access to resources and system reliability;
- Ensure that planned future transmission system improvements do not adversely affect neighboring systems; and
- Ensure the interconnected system's compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five- and ten-year periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

B. Transmission System Emerging Issues

Looking forward, several items that have the potential to impact the planning of the Duke Energy Carolinas Transmission System include:

- Industry-approved revisions to the NERC Reliability Standards for transmission planning standards that are awaiting FERC approval.

- FERC Order 1000 on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, issued in July 2011 under Docket No. RM10-23-000. Compliance filings under FERC Order 1000 are due on October 11, 2012 and April 11, 2013.

- Increased interest in the integration of variable renewable resources (e.g., wind) into the grid. The NCTPC and the DOE-funded Carolinas Offshore Wind Integration Case Study DOE-funded Southeastern Offshore Wind Energy Infrastructure Project are performing studies in 2012 to assess the transmission impacts of significant off-shore wind development along the Southeast coast including North Carolina.

- The Eastern Interconnection Planning Collaborative (EIPC), which is a transmission study process that began in late 2009. The EIPC provides:

  1. A mechanism to aggregate existing regional transmission plans in the Eastern Interconnection and assess them on an Eastern Interconnection wide basis; and
  2. A framework to be able to perform technical analyses to inform state and federal government representatives and policy makers on important issues, such as future renewable resources and their impact on transmission infrastructure.

  As of late July 2012, the EIPC is performing analysis to determine the specific transmission infrastructure needed to support three future resource scenarios as determined by the Stakeholder Steering Committee in late 2011. This analysis and a final report are scheduled to be completed by the end of 2012.

8. SELECTION AND IMPLEMENTATION OF THE PLAN

A. Resource Needs Assessment (Future State)

To meet the future needs of Duke Energy Carolinas' customers, it is necessary for the Company to adequately understand the load and resource balance. For each year of the planning horizon, Duke Energy Carolinas develops a load forecast of energy sales and peak demand. To determine total resources needed, the Company considers the load obligation plus a 15.5% target planning reserve margin (see Reserve Margin discussion below). The capability of existing resources, including generating units, energy efficiency and demand-side management programs, and purchased power contracts, is measured against the total resource need. Any deficit in future years will be met by a mix of additional resources that reliably and cost-effectively meet the load obligation.

Reserve Margin Explanation and Justification

Background

As part of the NCUC's approval of the 2010 IRP, Duke Energy Carolinas and Progress Energy Carolinas were ordered to perform a quantitative analysis of the utilities' respective reserve margins and to provide the study results in the companies' 2012 IRPs. Since the early 2000s, Duke Energy Carolinas' target reserve margin has been 17% with a minimum reserve margin of 15.5%. In place of a quantitative study over the past five years, the 17% reserve margin has been justified based on the Company's review of its actual reserves and operating experience. For example twice in the past 5 years, actual operating reserves have dropped to approximately 2% during times of peak demand supporting the 17% reserve margin. The NCUC approved the 17% planning reserve margin as reasonable for planning in each of the Company's IRPs from 2005 to 2011.

Duke Energy Carolinas hired Astrape, a consultant that specializes in reserve margin analysis, to perform the quantitative analysis. Astrape's analysis was detailed, incorporating uncertainty of weather, economic load growth, unit availability, hydro availability and transmission availability for emergency tie assistance.

Evaluation

Astrape evaluated a range of reserve margins based on a physical reliability metric and on an economic metric. A planning year of 2016 was used as the reference year because it incorporated the new generation units (Buck & Dan River CC, Cliffside 6) and the planned retirements.

The physical reliability metric targets a reserve margin that meets a one day in 10 year standard which is interpreted as one firm load shed event every 10 years. This is the most common metric used in the utility industry and is commonly referred to as Loss of Load Expectation (LOLE). A firm load shed event occurs when load plus operating reserves is greater than available capacity and all options including market purchases and demand response have been exhausted. This results in unserved energy for a firm customer. Based on the results of this analysis, a 14.5% reserve margin meets the one in every 10 year LOLE metric for Duke Energy Carolinas.

From an economic perspective, as planning reserve margin increases, the total cost of reserves increases while the costs related to reliability events decline. On the other hand, as planning reserve margin decreases, the cost of reserves decreases while the costs related to reliability events increases, including the costs to customers due to a loss of power. Thus, there is an economic optimum point where the cost of additional reserves plus the cost of reliability events on customers is minimized. The Astrape study shows that the optimal reserve margin that minimizes the cost to customers on a long term basis is 14%.

However, when a range of potential outcomes is examined, the study shows that at a 90% confidence interval, an economic benefit would be received by adding efficient natural gas combustion turbines up to a reserve margin of 15.5%. In addition, Astrape performed analyses using various sensitivities. The results demonstrate that a target reserve margin in the 14-16% range performs well in most sensitivity cases.

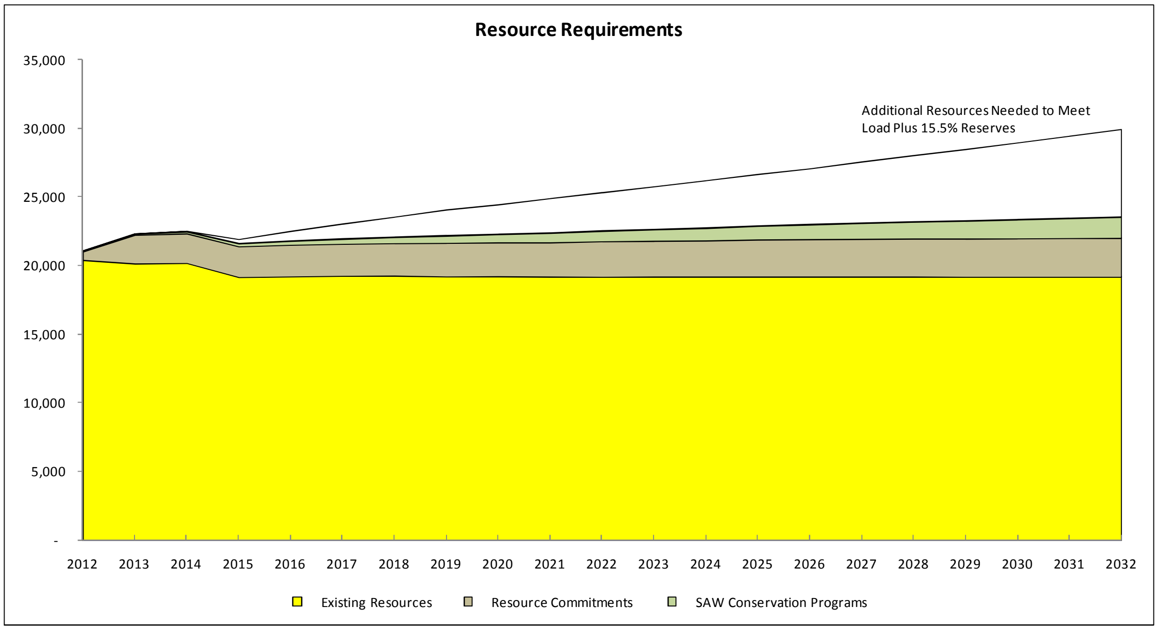
Based on the result of the analyses, the Company developed the 2012 IRP assuming a minimum planning reserve margin of 14.5% with a target of 15.5%. The 14.5% minimum planning reserve margin is 1% lower than the 2011 IRP minimum reserve margin of 15.5%, which is equivalent to an approximate 200 MW reduction in generation need in the 2016 timeframe. One factor that supports a lower reserve margin is the Company's retirement of the less reliable old fleet CTs and older coal units and replacement of such units with the new Buck and Dan River CCs and the new Cliffside Unit 6 coal unit. Carrying a lower reserve margin does come with the risk that additional purchase will be required from neighboring utilities during periods when there are low reserves. Duke Energy Carolinas expects such purchases to be infrequent and lower cost to customers than carrying a higher reserve margin.

Load and Resource Balance

In 2013, the load obligation plus the target planning reserve margin is 20,911 MW. Existing resources, consisting of existing generation and purchased power to meet load requirements, total 22,331 MW. The difference between available resources and the projected load obligation indicates there are sufficient resources to meet Duke Energy Carolinas' 2013 peak system requirements. However, the need for additional capacity grows over time due to load growth, unit capacity adjustments, unit retirements, and expirations of purchased-power contracts. In fact, the Company's forecasts predict new resource requirements of 2,770 MW by 2022 and 6,360 MW by 2032. The following chart shows the existing resources and resource requirements needed to meet the Company's load obligation, plus the 15.5% target planning reserve margin. Assumptions made in the development of this chart include:

1. Cliffside Unit 6 is online in the fall of 2012; included in Resource Commitments;
2. Coal retirements associated with the Cliffside Unit 6 CPCN and Air Permit, Buck Units 5&6, and Lee Steam Station are included;
3. Retirement of the old fleet combustion turbines in the fall of 2012 are included;
4. Conservation programs including those associated with the save-a-watt program are included;
5. DSM programs including those associated with the save-a-watt program are included;
6. Buck combined cycle facility was online in the fall of 2011 and Dan River combined cycle is online in the fall of 2012; both are included in Resource Commitments;
7. Renewable capacity is built or purchased to meet the NC REPS is included.

Chart 8.A
Load and Resource Balance



Cumulative Resource Additions to Meet a 15.5% Planning Reserve Margin (MWs)

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Resource Need	0	0	280	680	1070	1450	1860	2130	2500	2770

Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Resource Need	3100	3430	3740	4040	4440	4820	5180	5560	5960	6360

B. Overall Planning Process Conclusions

Duke Energy Carolinas' resource planning process provides a framework for the Company to access, analyze and implement a cost-effective approach to reliably meet customers' growing energy needs. In addition to assessing qualitative factors, the Company has also conducted a quantitative assessment using simulation models.

Duke Energy Carolinas tested a variety of sensitivities and scenarios against a base set of inputs for various resource mixes, allowing the Company to better understand how potentially different future operating environments due to fuel commodity price changes, environmental emission mandates, and structural regulatory requirements can affect resource choices, and, ultimately, the cost of electricity to customers. (Appendix A provides a detailed description and results of the quantitative analyses).

The results of the Company's quantitative analyses suggest that a combination of additional base load, intermediate and peaking generation, renewable resources, EE, and DSM programs is required over the next twenty years to meet customer demand reliably and cost-effectively.

The new pulverized coal unit at Cliffside Steam Station (Unit 6), scheduled to be in service in September 2012, is projected to provide 5,700 GWh of base load energy annually. The new CC facility at Dan River is also expected to be operational in late 2012. In addition, Duke Energy Carolinas has included DSM, EE and renewable resources consistent with the Company's energy efficiency plan approved in North and South Carolina and to meet the NC REPS. For planning purposes, a renewable energy standard similar to NC REPS was assumed for South Carolina beginning in 2016, in addition to the energy efficiency programs that will be phased in from 2015 to 2031. Nuclear uprates of approximately 100 MW are included in the 2012 IRP. Specific projects are being developed to be implemented in the 2013-2015 timeframe. For planning purposes, Lee Steam Station will be retired from coal-fired generation in late 2014 and Unit 3 will be converted to natural gas generation in 2015.

The Company's analysis of new nuclear capacity contained in the 2012 IRP focuses on the impact of various uncertainties such as load variations, nuclear capital costs, greenhouse gas and clean energy legislation, EPA regulations, fuel prices, and the availability of financing options such as federal loan guarantees (FLG).

The IRP analysis included sensitivities on each of the uncertainties described below:

Load Variations: The base case load forecast incorporates the impact of the current recession, projected EE achievements, new wholesale sales opportunities, and the impact associated with future plug-in hybrid vehicles. The Company also developed high and low load forecast sensitivities to reflect a 95% confidence interval.

Nuclear Capital Costs: The Company varied the nuclear capital cost on the low end to reflect the impact of minimal project contingency and low escalation rates and varied on the high side to reflect increased labor and material cost.

Nuclear Financing Options: The nuclear cost in the 2012 IRP includes state incentives, local incentives and federal loan guarantees.

Greenhouse Gas Legislation: The 2012 fundamental CO_2 allowance price forecast was delayed primarily due to uncertainty of Congress passing carbon legislation. For the 2012 IRP, the Company evaluated a range of CO_2 prices based on various legislative cap and trade proposals used in 2009 and 2010 IRPs, in addition to potential Clean Energy legislation that does not have a CO_2 cap and trade mechanism, but relies upon a federal RPS.

Fuel Prices: The base case natural gas and coal price projections were based on Duke Energy's fundamental price forecasts, which are updated annually. The Company also evaluated a high cost fuel scenario, which reflects the impact of increased demand on natural gas, regulatory challenges to the coal mining industry, and the potential impacts of changes to international exports of natural gas and domestic coal. The lower cost fuel scenario represents a larger supply of domestic natural gas than currently assumed and a lower demand on coal.

Results

The results of the Company's quantitative and qualitative analyses suggest that a combination of additional base load, intermediate, and peaking generation, renewable resources, and EE and DSM programs are required over the next 20 years. The near-term resource needs can be met, in part, with new EE and DSM programs, completing construction of the Dan River and Cliffside Projects, pursuing nuclear uprates and procuring renewable energy resources, as appropriate. However, additional resources will be needed as early as 2016 to meet forecasted system demand and energy requirements. As natural gas market price projections have decreased from 2011, construction and operation of efficient combined cycle capacity proves to be the most economical approach to meeting system needs in the next 5-7 years. However, even with a significant price decline in the natural gas market, the Company's analysis continues to affirm the potential benefits of new nuclear capacity in the 2022 timeframe in a carbon-constrained future.

To demonstrate that the Company is planning adequately for customers, the Company selected a portfolio incorporating the impact of future carbon legislation for the purposes of preparing the Load, Capacity, and Reserve Margin Table (LCR Table).

This portfolio consisted of 1,800 MW[4] of new natural gas simple cycle capacity, 2,100 MW of CC capacity, 2,234 MW of new nuclear capacity, 1,207 MW of DSM, 1,320 MW of EE, and 758 MW of renewable resources available on-peak. The selected portfolio specifically includes the Cliffside Unit 6, Dan River CC, and Lee Unit 3 natural gas conversion projects.

However, the Company will likely face significant challenges relating to its resource planning in the future, such as specific challenges in (1) obtaining the necessary regulatory approvals to implement future demand-side, EE, and supply-side resources, (2) finding sufficient cost-effective, reliable renewable resources to meet the standard, particularly the swine and poultry set-asides, (3) effectively integrating renewables into the resource mix, particularly with the expected increase in solar QFs, (4) ensuring sufficient transmission capability for these resources, and (5) encouraging customers to adopt EE and DSM measures at the levels assumed in the resource plan. In light of the myriad of qualitative issues facing the Company relating to its fuel diversity, the Company's environmental profile, the stage of technology deployment and regional economic development, Duke Energy Carolinas has developed a strategy to ensure that the Company can meet customers' energy needs reliably and economically while maintaining flexibility pertaining to long-term resource decisions.

Challenges and Considerations for New and Existing Nuclear Generation

In March of 2012, the NRC issued a request for information letter to operating power reactor licensees regarding recommendations of the Near-Term Task Force review of insights from the Fukushima Dai-ichi accident. In April 2012, the NRC staff subsequently requested Duke Energy to update the W.S. Lee III (Lee) plant site-specific seismic analysis to incorporate the new Central and Eastern United States (CEUS) Seismic Source Characterization model (published as NUREG-2115 in January 2012). Work on a new Lee site-specific analysis implementing the new CEUS seismic model is underway. However, completion of the new seismic analysis is not expected before December 2012. This negatively impacts the schedule for NRC issuance of the Lee Combined Operating License (COL). The prior NRC schedule for Lee COL issuance in March-April 2013 supported a Commercial Operation Date (COD) of 2021. Completion of the new site-specific seismic analysis will delay Lee COL issuance beyond the second Quarter 2013, which does not support a 2021 COD. Accordingly, Duke Energy

[4] The ultimate sizes of any generating unit may change somewhat depending on the vendor selected.

Carolinas has moved the COD for Lee Nuclear Unit 1 to 2022.

The NRC issued an updated Waste Confidence Rule in 2010 affirming that the agency has reasonable assurance utility spent fuel can be safely stored for at least 60 years after a power reactor's operating license expires. Waste confidence is central to the agency's ability to license new reactors and renew the operating licenses of existing reactors. On June 8, 2012, the US Court of Appeals of the District of Columbia Circuit issued a decision vacating the updated Waste Confidence Rule and remanding it to the NRC for further proceedings. The Court held that the NRC’s analysis was insufficient to support its findings that the permanent storage will be available “when necessary,” and that spent fuel can safely be stored onsite at nuclear plants for sixty years after the expiration of a plant’s license. In response to the remand decision, numerous parties filed a petition to suspend final decisions in all pending reactor licensing proceedings pending completion of remanded waste confidence proceedings in new nuclear and license renewal proceedings pending before the NRC. On August 7, 2012, the NRC issued an order on the petition stating that: (1) it is considering all options for resolving the waste confidence issues, which could include generic or site specific actions, but has not yet determined a course of action. (2) it will not issue licenses dependent on the waste confidence rule until the Court’s remand is appropriately addressed, however, this determination extends only to final license issuance; and (3) all licensing reviews and proceedings should continue to move forward. This is an emerging issue that could affect the issuance of the Lee COL.

The Oconee Nuclear Station’s (Oconee) current operating license expires in 2033, which is close to the end of our current IRP planning horizon. At this time, the Company has not made a decision concerning a second license extension for this plant. Oconee is a significant part of Duke Energy Carolinas’ generation portfolio representing over 2,500 MW of capacity and annual energy output of approximately 20,000 GWHs. As such, it is important to start to examine the impacts of any potential retirement of Oconee to help the Company as it considers a second license extension, as well as incorporate these impacts into the resource planning process.

In summary, the Company’s planning process must be dynamic and adaptable to changing conditions. This plan is the most appropriate resource plan at this point in time, however, good business practice requires Duke Energy Carolinas to continue to study the options, and make adjustments as necessary and practical to reflect improved information and changing circumstances. Consequently, a good business planning analysis is truly an evolving process that can never be considered complete.

The seasonal projections of load, capacity, and reserves of the selected plan are provided in Table 8.A.

Table 8.A

Summer Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2012 Annual Plan

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Load Forecast																				
1 Duke System Peak	18,105	18,554	18,975	19,486	19,947	20,386	20,830	21,155	21,552	21,921	22,296	22,673	23,073	23,420	23,859	24,260	24,643	25,051	25,483	25,905
Reductions to Load Forecast																				
2 New EE Programs	(62)	(117)	(181)	(247)	(317)	(384)	(451)	(517)	(585)	(652)	(720)	(785)	(854)	(921)	(988)	(1,053)	(1,123)	(1,190)	(1,257)	(1,320)
3 Adjusted Duke System Peak	**18,043**	**18,437**	**18,795**	**19,239**	**19,630**	**20,002**	**20,379**	**20,638**	**20,967**	**21,268**	**21,577**	**21,888**	**22,219**	**22,499**	**22,871**	**23,208**	**23,520**	**23,861**	**24,227**	**24,585**
Cumulative System Capacity																				
4 Generating Capacity	19,913	21,044	21,109	20,211	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207
5 Capacity Additions	1,481	66	182	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	0	0	0	(4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	(350)	0	(1,080)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	21,044	21,109	20,211	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207	20,207
Purchase Contracts																				
9 Cumulative Purchase Contracts	340	340	328	328	328	328	261	258	170	155	155	155	155	155	155	155	141	141	141	141
Sales Contracts																				
10 Catawba Owner Backstand	0	(47)	(47)	(47)	(47)	(47)	(47)	(47)	0	0	0	0	0	0	0	0	0	0	0	0
11 Firm Sale	(150)	(150)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	0	0	0	0	0	1,117	1,117	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	0	0	0	700	700	1,400	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,900	2,900	3,700	3,700	3,850
Renewables	38	103	171	231	256	288	374	395	426	516	536	567	637	661	684	701	715	729	743	758
13 Cumulative Production Capacity	**21,272**	**21,356**	**20,664**	**21,419**	**21,444**	**22,177**	**22,994**	**23,013**	**23,003**	**24,195**	**24,215**	**25,363**	**25,433**	**25,457**	**25,480**	**26,198**	**26,197**	**27,011**	**27,025**	**27,190**
Reserves w/o Demand-Side Management																				
14 Generating Reserves	3,229	2,919	1,870	2,180	1,814	2,175	2,616	2,374	2,036	2,927	2,639	3,475	3,214	2,958	2,609	2,990	2,677	3,150	2,799	2,605
15 % Reserve Margin	**17.9%**	**15.8%**	**9.9%**	**11.3%**	**9.2%**	**10.9%**	**12.8%**	**11.5%**	**9.7%**	**13.8%**	**12.2%**	**15.9%**	**14.5%**	**13.1%**	**11.4%**	**12.9%**	**11.4%**	**13.2%**	**11.6%**	**10.6%**
16 % Capacity Margin	15.2%	13.7%	9.0%	10.2%	8.5%	9.8%	11.4%	10.3%	8.9%	12.1%	10.9%	13.7%	12.6%	11.6%	10.2%	11.4%	10.2%	11.7%	10.4%	9.6%
Demand-Side Management																				
17 Cumulative DSM Capacity	872	956	1,043	1,099	1,140	1,153	1,167	1,180	1,194	1,200	1,207	1,207	1,207	1,207	1,207	1,207	1,207	1,207	1,207	1,207
IS / SG	100	95	90	86	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82
Power Share / Power Manager	772	861	953	1,013	1,058	1,071	1,085	1,098	1,112	1,118	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125
18 Cumulative Equivalent Capacity	**22,144**	**22,312**	**21,707**	**22,518**	**22,584**	**23,329**	**24,161**	**24,193**	**24,197**	**25,395**	**25,422**	**26,570**	**26,640**	**26,664**	**26,687**	**27,405**	**27,404**	**28,218**	**28,232**	**28,397**
Reserves w/ DSM																				
19 Generating Reserves	4,101	3,875	2,912	3,279	2,954	3,328	3,783	3,554	3,230	4,127	3,846	4,682	4,421	4,165	3,816	4,197	3,884	4,357	4,006	3,812
20 % Reserve Margin	**22.7%**	**21.0%**	**15.5%**	**17.0%**	**15.0%**	**16.6%**	**18.6%**	**17.2%**	**15.4%**	**19.4%**	**17.8%**	**21.4%**	**19.9%**	**18.5%**	**16.7%**	**18.1%**	**16.5%**	**18.3%**	**16.5%**	**15.5%**
21 % Capacity Margin	18.5%	17.4%	13.4%	14.6%	13.1%	14.3%	15.7%	14.7%	13.3%	16.3%	15.1%	17.6%	16.6%	15.6%	14.3%	15.3%	14.2%	15.4%	14.2%	13.4%

Winter Projections of Load, Capacity, and Reserves
for Duke Energy Carolinas 2012 Annual Plan

	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32
Load Forecast																				
1 Duke System Peak	17,443	17,868	18,295	18,744	19,224	19,672	20,112	20,474	20,764	21,179	21,527	21,880	22,260	22,585	22,958	23,418	23,816	24,209	24,628	25,005
Reductions to Load Forecast																				
2 New EE Programs	(60)	(109)	(164)	(219)	(303)	(369)	(435)	(489)	(567)	(633)	(699)	(763)	(814)	(879)	(963)	(1,027)	(1,095)	(1,162)	(1,203)	(1,264)
3 Adjusted Duke System Peak	**17,383**	**17,759**	**18,130**	**18,526**	**18,921**	**19,303**	**19,677**	**19,985**	**20,197**	**20,546**	**20,828**	**21,117**	**21,446**	**21,706**	**21,994**	**22,391**	**22,720**	**23,048**	**23,425**	**23,740**
Cumulative System Capacity																				
4 Generating Capacity	20,318	21,766	21,801	21,867	20,969	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965
5 Capacity Additions	2,074	36	66	182	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Capacity Derates	0	0	0	0	(4)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Capacity Retirements	(626)	0	0	(1,080)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 Cumulative Generating Capacity	21,766	21,801	21,867	20,969	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965	20,965
Purchase Contracts																				
9 Cumulative Purchase Contracts	347	347	335	335	335	335	268	265	170	155	155	155	155	155	155	155	141	141	141	141
Sales Contracts																				
10 Catawba Owner Backstand	0	(47)	(47)	(47)	(47)	(47)	(47)	(47)	0	0	0	0	0	0	0	0	0	0	0	0
11 Firm Sale	(25)	(25)	(25)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 Cumulative Future Resource Additions																				
Base Load	0	0	0	0	0	0	0	0	0	0	1,117	1,117	2,234	2,234	2,234	2,234	2,234	2,234	2,234	2,234
Peaking/Intermediate	0	0	0	0	700	700	1,400	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,900	2,900	3,700	3,700
Renewables	16	38	103	171	231	256	288	374	395	426	516	536	567	637	661	684	701	715	729	743
13 Cumulative Production Capacity	**22,103**	**22,115**	**22,233**	**21,429**	**22,184**	**22,209**	**22,873**	**23,756**	**23,729**	**23,746**	**24,953**	**24,973**	**26,121**	**26,191**	**26,215**	**26,238**	**26,941**	**26,955**	**27,769**	**27,783**
Reserves w/o Demand-Side Management																				
14 Generating Reserves	4,720	4,356	4,103	2,903	3,263	2,906	3,197	3,771	3,532	3,200	4,125	3,856	4,675	4,485	4,220	3,847	4,221	3,907	4,344	4,043
15 % Reserve Margin	**27.2%**	**24.5%**	**22.6%**	**15.7%**	**17.2%**	**15.1%**	**16.2%**	**18.9%**	**17.5%**	**15.6%**	**19.8%**	**18.3%**	**21.8%**	**20.7%**	**19.2%**	**17.2%**	**18.6%**	**17.0%**	**18.5%**	**17.0%**
16 % Capacity Margin	21.4%	19.7%	18.5%	13.5%	14.7%	13.1%	14.0%	15.9%	14.9%	13.5%	16.5%	15.4%	17.9%	17.1%	16.1%	14.7%	15.7%	14.5%	15.6%	14.6%
Demand-Side Management																				
17 Cumulative DSM Capacity	570	595	617	635	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653	653
IS / SG	100	95	90	86	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82	82
Power Share / Power Manager	470	500	527	549	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571	571
18 Cumulative Equivalent Capacity	**22,673**	**22,710**	**22,850**	**22,063**	**22,837**	**22,862**	**23,526**	**24,409**	**24,382**	**24,399**	**25,606**	**25,626**	**26,774**	**26,844**	**26,868**	**26,891**	**27,594**	**27,608**	**28,422**	**28,436**
Reserves w/ DSM																				
19 Generating Reserves	5,290	4,951	4,719	3,537	3,916	3,559	3,849	4,424	4,185	3,853	4,777	4,509	5,328	5,138	4,873	4,499	4,874	4,560	4,997	4,696
20 % Reserve Margin	**30.4%**	**27.9%**	**26.0%**	**19.1%**	**20.7%**	**18.4%**	**19.6%**	**22.1%**	**20.7%**	**18.8%**	**22.9%**	**21.3%**	**24.8%**	**23.7%**	**22.2%**	**20.1%**	**21.5%**	**19.8%**	**21.3%**	**19.8%**
21 % Capacity Margin	23.3%	21.8%	20.7%	16.0%	17.1%	15.6%	16.4%	18.1%	17.2%	15.8%	18.7%	17.6%	19.9%	19.1%	18.1%	16.7%	17.7%	16.5%	17.6%	16.5%

Assumptions of Load, Capacity, and Reserves Table

The following notes are numbered to match the line numbers on the Summer and Winter Projections of Load, Capacity, and Reserves tables. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke System including Nantahala. Nantahala became a division of Duke Energy Carolinas in 1998.

4. Generating Capacity must be online by June 1 to be included in the available capacity for the summer peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter peak of that year. Includes 101 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale.

5. Capacity Additions include Duke Energy Carolinas projects that have been approved by the NCUC (Cliffside 6, Dan River Combined Cycle facility).
   Capacity Additions include the conversion of Lee Steam Station unit 3 from coal to natural gas in 2015 (170 MW).
   Capacity Additions include Duke Energy Carolinas hydro units scheduled to be repaired and returned to service. These units are returned to service in the 2012-2015 timeframe and total 2 MW.
   Also included is a 111 MW capacity increase due to nuclear uprates at Catawba, McGuire, and Oconee. Timing of these uprates is shown from 2012-2015

6. Capacity Derate of 4 MW associated with Marshall 4 SCR is included in 2016

7. The 350 MW capacity retirement in summer 2013 represents the projected fall 2012 retirement date for the old fleet CT retirements
   The 1080 MW capacity retirement in summer 2015 represents the projected retirement date for Lee Steam Station (370 MW), Buck Steam Station units 5 and 6 (256 MW) and Riverbend Steam Station units 4-7 (454 MW).
   The NRC has issued renewed energy facility operating licenses for all Duke Energy Carolinas' nuclear facilities.
   The Hydro facilities for which Duke has submitted an application to FERC for licence renewal are assumed to continue operation through the planning horizon.
   All retirement dates are subject to review on an ongoing basis.

9. Cumulative Purchase Contracts have several components:

   A. Piedmont Municipal Power Agency took sole responsibility for total load requirements beginning January 1, 2006. This reduces the SEPA allocation from 94 MW to 19 MW in 2006, which is attributed to certain wholesale customers who continue to be served by Duke.
   B. Purchased capacity from PURPA Qualifying Facilities includes the 88 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2020 and miscellaneous other QF projects totaling 132 MW in 2013.

10-11. A firm wholesale backstand agreement up to 277 MW between Duke Energy Carolinas and PMPA starts on 1/1/2014 and continues through the end of 2020. Firm sale of 150 MW summer and 25 MW winter for FERC market power mitigation.

12. Cumulative Future Resource Additions represent a combination of new capacity resources or capability increases from the most robust plan.

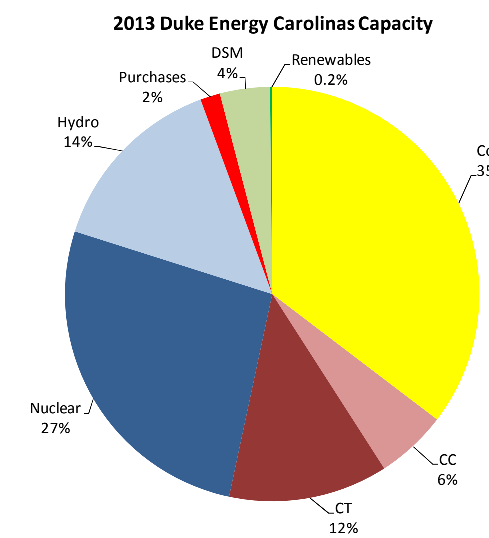
15. Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand
    Occurences when Reserve Margin exceeds +/-3% of the 15.5% target planning reserve margin:2013-2014 Reserve Margin
    1) 2013-2014: Due to the addition of Buck and Dan River CC and Cliffside 6 PC units coupled with lower economic load growth.
    2) 2019: Due to the addition of 800 MW of CT capacity to meet resource need in 2019, 2020 and 2021.
    3) 2022, 2024, and 2025: Due to the addition of 1117 MW nuclear units to meet long-term resource need in 2022 and 2024.

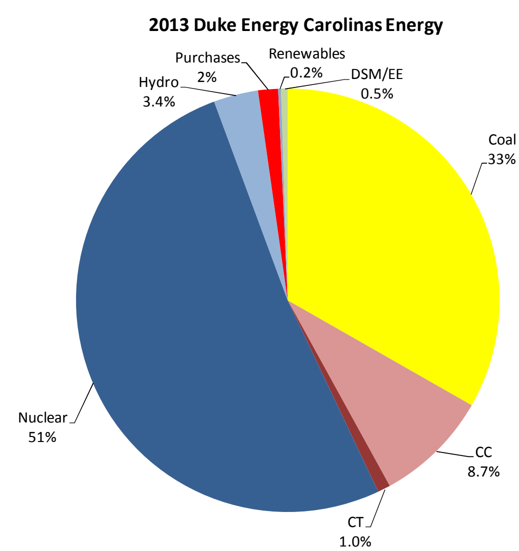
16. Capacity Margin = (Cumulative Capacity - System Peak Demand)/Cumulative Capacity

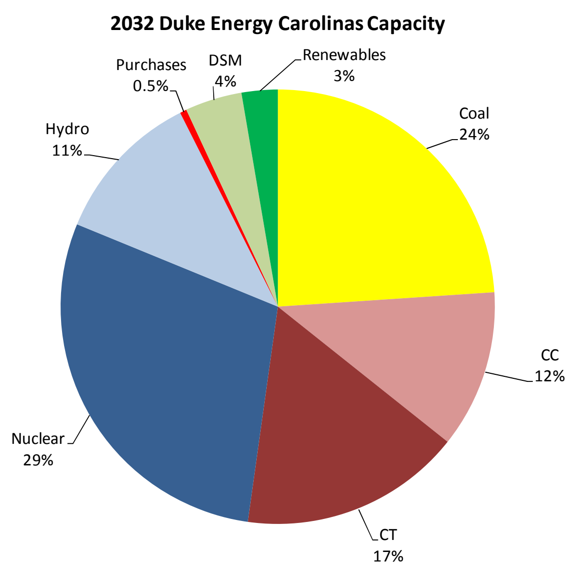
17. The Cumulative Demand Side Management capacity includes new Demand Side Management capacity representing placeholders for demand response and energy efficiency programs.

The charts in Chart 8.B and 8.C show the changes in Duke Energy Carolinas' capacity mix and energy mix between 2013 and 2032. The relative shares of renewables, energy efficiency, and gas all increase, while the relative share of coal decreases.

Chart 8.B







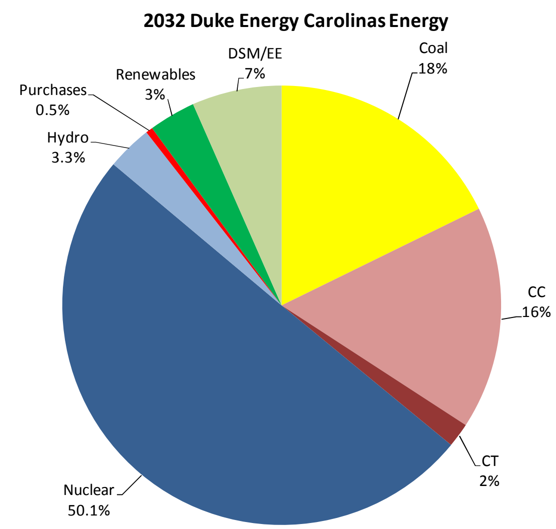
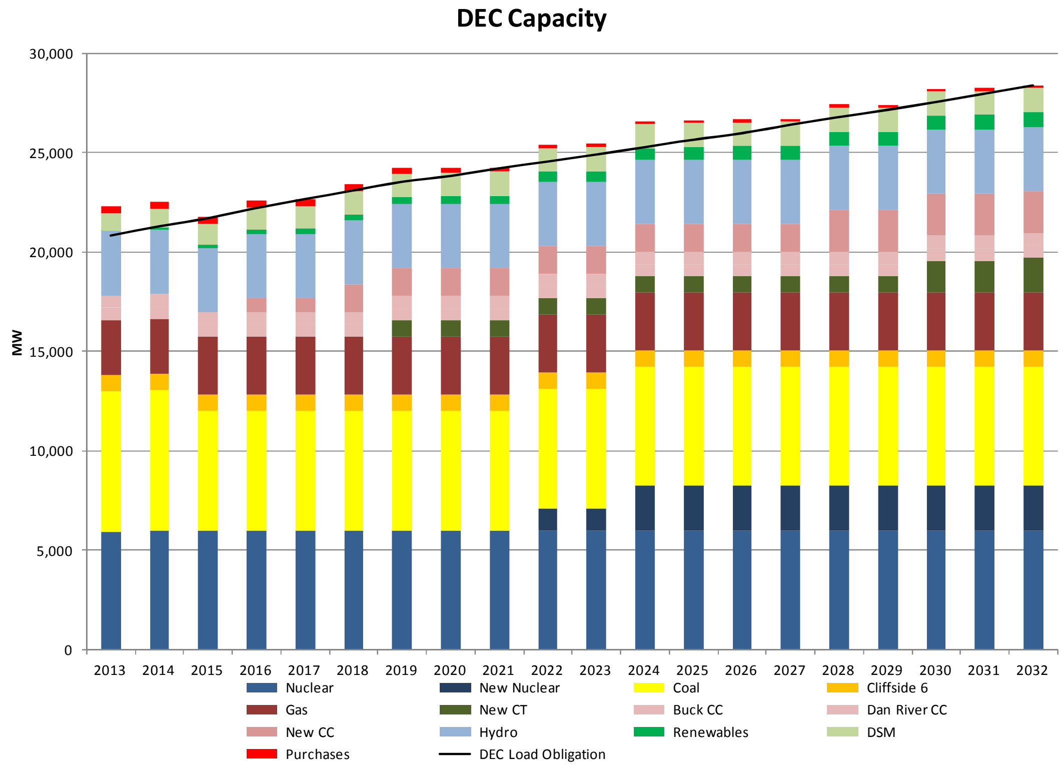


Chart 8.C
Annual Capacity Projection 2013 through 2032



Annual Energy Projection 2013 through 2032

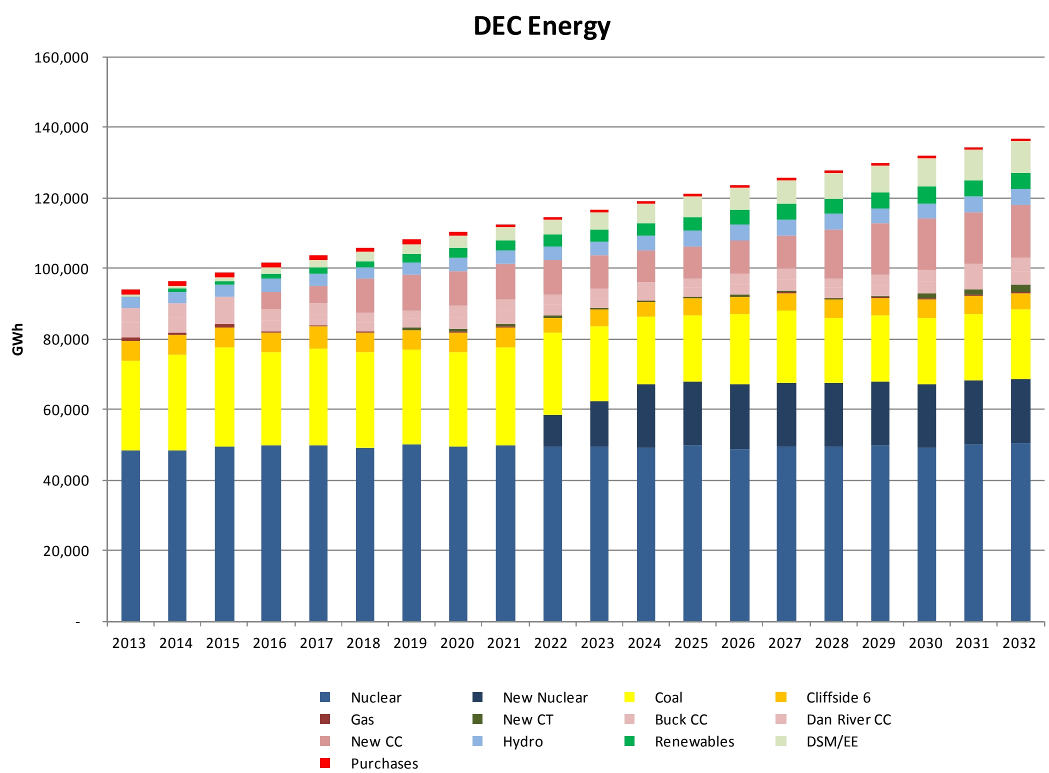


Table 8.D below represents the annual non-renewable incremental additions reflected in the LCR Table of the most robust expansion plan. The plan contains the addition of Cliffside Unit 6 in 2012, the unit retirements shown in Table 5.D and the impact of EE and DSM programs.

Table 8.D

Year	Month	Project	MW
2012	6	Bridgewater Hydro	8.75
2012	9	Cliffside 6	825
2012	12	Dan River Combined Cycle	620
2013	6	Nuclear Uprates	34
2014	6	Nuclear Uprates	65
2015	6	Nuclear Uprates	12
2016	6	New CC	700
2018	6	New CC	700
2019	6	New CT	800
2022	1	New Nuclear	1117
2023	8	New Nuclear	1117
2028	6	New CC	700
2030	6	New CT	800

The details of the forecasted capacity additions, including both nameplate capacity and the expected contribution of renewable resources towards Duke Energy Carolinas' peak load needs, are summarized in Table 8.E below.

Table 8.E Expected Renewable Resource Capacity Additions

Renewables								
	MW Contribution to Summer Peak				MW Nameplate			
Year	Wind	Solar	Biomass	Total	Wind	Solar	Biomass	Total
2012	6	8	1	16	40	17	1	58
2013	0	28	10	38	0	56	10	66
2014	15	68	20	103	100	135	20	256
2015	15	127	30	171	100	253	30	383
2016	20	160	51	231	134	320	51	505
2017	20	176	60	256	135	352	60	546
2018	20	199	68	288	135	398	68	602
2019	48	235	90	374	322	471	90	883
2020	48	247	99	395	323	495	99	917
2021	49	269	108	426	324	538	108	970
2022	56	324	135	516	376	649	135	1160
2023	57	346	133	536	378	692	133	1204
2024	57	368	142	567	381	736	142	1258
2025	62	420	154	637	416	840	154	1411
2026	63	443	155	661	419	885	155	1459
2027	63	464	156	684	422	928	156	1507
2028	65	473	163	701	430	946	163	1540
2029	66	483	166	715	439	965	166	1571
2030	67	492	170	729	448	984	170	1602
2031	69	502	173	743	457	1004	173	1633
2032	69	502	173	758	457	1004	173	1665

APPENDICES

APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the Company's quantitative analysis of resource options available to meet customers' future energy needs.

Overview of Analytical Process

The analytical process consists of five steps:

1. Assess resource needs
2. Identify resource options and screen for further consideration
3. Develop theoretical portfolio configurations
4. Develop final portfolio options
5. Perform portfolio analysis

Assess Resource Needs

Duke Energy Carolinas estimates the required load and generation resource balance needed to meet future customer demands by assessing:

- Customer load forecast peak and energy – identifying future customer aggregate demands to identify system peak demands and developing the corresponding energy load shape
- Existing supply-side resources – summarizing each existing generation resource's operating characteristics including unit capability, potential operational constraints, and life expectancy
- Operating parameters – determining operational requirements including target planning reserve margins and other regulatory considerations.

Customer load growth coupled with the expiration of purchased power contracts, lower demand response, and renewable compliance assumptions, results in significant resource needs to meet energy and peak demands, based on the following assumptions:

- 1.9% average summer peak system demand growth over the next 20 years without impacts of new energy efficiency programs and 1.7% summer peak demand growth with energy efficiency impacts
- Generation retirements of approximately 350 MW of old fleet combustion turbines by the end of 2012
- Generation retirements of approximately 1,040 MW of older coal units associated with the addition of Cliffside Unit 6.

- Generation retirements of approximately 630 MW of remaining coal units without scrubbers by 2015
- Approximately 70 MW of net generation reductions as a result of unit derates associated with new environmental equipment
- Continued operational reliability of existing generation portfolio
- A 15.5% target planning reserve margin for the planning horizon

Identify and Screen Resource Options for Further Consideration

The IRP process evaluates EE, DSM and supply-side options to meet customer energy and capacity needs. The Company develops DSM/EE options for consideration within the IRP based on input from our collaborative partners and cost-effectiveness screening. Supply-side options reflect a diverse mix of technologies and fuel sources (gas, coal, nuclear and renewable). Supply-side options are initially screened based on the following attributes:

- Technically feasible and commercially available in the marketplace
- Compliant with all federal and state requirements
- Long-run reliability
- Reasonable cost parameters.

The Company compared capacity options within their respective fuel types and operational capabilities, with the most cost-effective options being selected for inclusion in the portfolio analysis phase.

Resource Options

<u>Supply-Side</u>
Based on the results of the screening analysis, the following technologies were included in the quantitative analysis as potential supply-side resource options to meet future capacity needs:

- Base load – 825 MW Supercritical Pulverized Coal with CCS
- Base load – 618 MW IGCC with CCS
- Base load – 2 x 1,117MW Nuclear units (AP1000)
- Base load – 700 MW – 2x2x1 Combined Cycle (inlet chiller and duct fired)
- Peaking/Intermediate – 800 MW (4 x 200 MW) Simple Cycle CT
- Renewable – 150 MW Wind - On-Shore
- Renewable – 5 MW Landfill Gas
- Renewable – 25 MW Solar PV

Although the supply-side screening curves showed that some of these resources would be screened out, they were included in the next step of the quantitative analysis for completeness.

Energy Efficiency and Demand-Side Management

EE and DSM programs continue to be an important part of Duke Energy Carolinas' system mix. The Company considered both demand response and conservation programs in the analysis.

The Company modeled the program costs associated with EE and DSM based on a combination of both internal company expectations and projections based on information from the Company's 2011 Market Potential Study. These program costs are expected to increase throughout the planning horizon as additional EE and DSM measures are implemented.

Develop Theoretical Portfolio Configurations

The Company conducted a screening analysis using a simulation model to identify the most attractive capacity options under the expected load profile as well as under a range of sensitivities. This analysis began with a set of basic inputs which were varied to test the system under different future conditions, such as changes in fuel prices, load levels, and construction costs. These analyses yielded many different theoretical configurations of resources required to meet an annual 15.5% target planning reserve margin while minimizing the long-run revenue requirements to customers, with differing operating (production) and capital costs.

The set of basic inputs included:

- Fuel costs and availability for coal, gas, and nuclear generation
- Development, operation, and maintenance costs of both new and existing generation
- Compliance with current and potential environmental regulations;
- Cost of capital
- System operational needs for load ramping, spinning reserve (10 to 15-minute start-up)
- The projected load and generation resource need
- A menu of new supply side and EE/DSM resource options with corresponding costs and timing parameters

Duke Energy Carolinas reviewed a number of variations to the theoretical portfolios to aid in the development of the portfolio options discussed in the following section.

Develop Final Portfolio Options

Using the insights gleaned from developing theoretical portfolios, Duke Energy Carolinas created a representative range of generation plans reflecting plant designs, lead times and environmental emissions limits. Recognizing that different generation plans expose customers to different sources and levels of risk, the Company developed a variety of portfolios to assess the impact of various risk factors on the costs to serve customers. The portfolios analyzed for the development of this IRP were chosen to focus on the optimal timing of CT, CC, and nuclear additions in the 2016 – 2032 timeframe.

The information as shown on the following pages outlines the planning options that the Company considered in the portfolio analysis phase. Each portfolio contains demand response and conservation identified in the base EE and DSM case and renewable portfolio standard requirements modeled after the NC REPS in NC and applied to SC. In addition, each portfolio contains the addition of Cliffside Unit 6 in September 2012, Dan River CC in December 2012, Lee Unit 3 Gas Conversion in January 2015 and the unit retirements shown in Table 5.D.

The RPS assumptions are based on NC REPS in North Carolina. The assumptions for planning purposes are as follows:

Overall Requirements/Timing

- 3% of 2011 load by 2012
- 6% of 2014 load by 2015
- 10% of 2017 load by 2018
- 12.5% of 2020 load by 2021

Additional Requirements

- Up to 25% from EE through 2020
- Up to 40% from EE starting in 2021
- Up to 25% of the requirements can be met with out-of-state, unbundled RECs
- Solar requirement
    - 0.02% by 2010
    - 0.07% by 2012
    - 0.14% by 2015
    - 0.20% by 2018

- Swine waste requirement (NC only – using Duke Energy Carolinas' share of total North Carolina load which is approximately 43%)
    - 0.07% by 2012
    - 0.14% by 2015
    - 0.20% by 2018
- Poultry waste requirement (NC only - using Duke Energy Carolinas' share of total North Carolina load which is approximately 43%)
    - 72,700 MWh by 2012
    - 292,000 MWh by 2013
    - 384,000 MWh by 2014

Compliance with these requirements can be met with a combination of EE programs, in-state RECs, out-of-state RECs, thermal RECs, and renewable projects that supply energy to the resource inventory. The costs associated with each of these resources are included in the resource plan, but only those that provide capacity and energy are used in the development of the resource plan.

The overall requirements were applied to all retail load and to wholesale customers who have contracted with Duke Energy Carolinas to meet their REPS requirement. The requirement that a certain percentage must come from Swine and Poultry waste was not applied to the South Carolina portion.

Conduct Portfolio Analysis

Duke Energy Carolinas tested the portfolio options under the nominal set of inputs, as well as a variety of risk sensitivities and scenarios, in order to understand the strengths and weaknesses of various resource configurations and evaluate the long-term costs to customers under various potential outcomes.

For this IRP analysis, the Company selected three main portfolios to illustrate the impacts of key risks and decisions. Each portfolio includes renewable resources to meet regulatory requirements and the base amount of EE/DSM resources as shown in Table 4.A.

The three analyzed portfolios are shown below:

1. Natural Gas – Combustion turbine/combined cycle portfolio (CT/CC)
2. Nuclear – Two nuclear unit portfolio with units on-line by the summer peak of 2022 and 2024 (Nuclear)
3. Regional Nuclear – Co-ownership of nuclear units in the region. The portfolio consists of 215 MW of nuclear by 2018, 730 MW in 2022 and 2024, and 558 MW in 2028

The sensitivities performed for these scenarios were those representing the highest risks going forward.

The Company evaluated the following sensitivities:

- Load forecast variations
  - Annual increase relative to base forecast (+7% for peak demand and +6% for energy by 2032)
  - Annual decrease relative to base forecast (-7% for peak demand and -8% for energy by 2032)
- Construction cost sensitivity[5]
  - Costs to construct a new nuclear plant (+20/- 10% higher than base case)
  - Costs to construct a new combined cycle plant (+30/- 5% higher than base case)
- Fuel price variability
  - Higher Fuel Prices (coal prices 25% higher, natural gas prices 35% higher)
  - Lower Fuel Prices (coal prices 40% lower, natural gas prices 20% lower)
- High EE and DSM
  - For EE, this sensitivity assumes full compliance with the Duke Energy-Progress Energy merger settlement agreement with the cumulative EE achievements since 2009 counted toward the cumulative settlement agreement impacts. The incremental impacts stop in 2031 after reaching the full economic potential of 16.5 million MWH. For DSM, an additional 100 MW of load curtailment is added by 2017.
- Carbon Emission Price
  - The reference case is a cap and trade program with CO_2 emission prices based on the Company's 2012 fundamental prices. The prices ranged from $17/ton starting in 2020 to $44/ton in 2032. The reference CO_2 prices fall at the lower end of the range of prices that were estimated to result from federal climate change legislation that was proposed and debated in Congress over the past few years.
  - The Company also performed a sensitivity analysis with higher CO_2 costs ranging from $31/ton in 2020 to $80/ton in 2032.
- Clean Energy Legislation: Assumptions used in this analysis include:
  - No carbon emission price.
  - 10% of retail sales by 2015 must be clean energy, increasing to 30% by 2030

[5] These sensitivities test the risks from increases in construction costs of one type of supply-side resource at a time. In reality, cost increases of many construction component inputs such as labor, concrete and steel would affect all supply-side resources to varying degrees rather than affecting one technology in isolation.

- Alternative compliance payment of 30$/MWh
- "Clean Energy" includes renewable resources, EE, nuclear, natural gas CC, or alternative compliance payment

- No Carbon Emission Price
  - Although the Company believes there will be a carbon constrained future a sensitivity analysis without a CO_2 emission price was provided to show the relative impact of carbon on the nuclear and gas portfolios. In addition, a sensitivity analysis was also performed with higher fuel prices to reflect the impact fuel volatility can have on the portfolios without carbon prices.

An overview of the specifics of each portfolio is shown in Table A.1 below.

Table A.1 - Portfolios Evaluated

Year	Portfolios		
	CT/CC	Nuclear	Regional Nuclear
2012			
2013			
2014			
2015			
2016	CC	CC	CC
2017			N
2018	CC	CC	N, CC
2019	CT	CT	
2020			CT
2021			
2022	CC	N	N
2023			
2024	CC	N	N
2025			
2026			
2027	CC		CC
2028	CT	CC	N
2029			
2030		CT	CT
2031	CC		
2032	CT	CT	CT
Total CT	1,930 MW	1,800 MW	1,800 MW
Total CC	4,200 MW	2,100 MW	2,100 MW
Total Nuclear		2,234 MW	2,234 MW
Total Nuclear Uprate	111 MW	111 MW	111 MW

Quantitative Analysis Results

Three potential resource planning strategies were tested under base assumptions and variations in CO_2 price, fuel costs, load/energy efficiency, and nuclear and combined cycle capital costs. These three potential resource planning strategies are:

- No new nuclear capacity (the CT/CC portfolio)
- Full ownership of new nuclear capacity (the 2 Nuclear Units portfolio)
- Regional co-ownership of new nuclear capacity (the Regional Nuclear portfolio)

For the base case and sensitivities, the Company calculated the PVRR for each portfolio. The revenue requirement calculation estimates the costs to customers for the Company to recover system production costs and new capital incurred. Duke Energy Carolinas used a 50-year analysis time frame to fully capture the long-term impact of nuclear generation added in the 20 year planning horizon. Table A.2 below represents a comparison of the Natural Gas (CT/CC) portfolio with a full ownership nuclear portfolio (1st unit in 2022 & 2nd unit in 2024) and the regional nuclear portfolio over a range of sensitivities. The green block represents the lowest PVRRs between the Natural Gas and the two nuclear portfolios. The value contained within the block is the PVRR savings in $billions between the cases.

Table A.2 - Comparison of Nuclear Portfolios to the CT/CC Portfolio ($ Billions)

	Reference Case	CO2 Price	Fuel Sensitivity		Clean Energy
Portfolio	Base[5]	High CO_2	High Fuel Cost	Low Fuel Cost	$30 ACP
Nuclear		(3.0)	(3.1)		(2.5)
Regional Nuclear	(0.1)	(3.1)	(3.2)		(2.5)
CT/CC	0.01 Nucl			2.1 Nucl / 1.8 Reg	

	Load Sensitivity			No Carbon Sensitivity	
Portfolio	High Load	Low Load	High EE & DSM	No Cost	No Cost / High Fuel
Nuclear	(0.01)				
Regional Nuclear	(0.07)				
CT/CC		0.7 Nucl / 0.6 Reg	0.6 Nucl / 0.4 Reg	3.8 Nucl / 3.5 Reg	0.9 Nucl / 0.6 Reg

	Capital Cost Sensitivity			
Portfolio	Nuclear 20% Increase	Nuclear 10% Decrease	Gas 30% Increase	Gas 5% Decrease[6]
Nuclear		(1.2)	(0.7)	
Regional Nuclear		(1.3)	(0.8)	(0.02)
CT/CC	2.4 Nucl / 2.2 Reg			0.1 Nucl

[6] The difference between the CT/CC and Nuclear portfolios is less than $10 million.

Based on the quantitative analysis, the recommended plan includes two new nuclear units in the 2020 timeframe. The nuclear portfolios and the natural gas portfolio are essentially breakeven in the base portfolios. Even with lower natural gas prices, increased CC efficiency, increased energy efficiency and lower projected load for the 2012 IRP, the portfolios with nuclear remain competitive with natural gas portfolios. It is the Company's belief that there is more upside risk in fuel cost as reflected in the fuel price sensitivities. The high fuel price sensitivity shows that small increases in fuel price would impact the cost-effectiveness of the nuclear portfolios. In a Clean Energy Standard regulatory construct, the cost benefits of adding additional nuclear are greater than in a CO_2 Cap and Trade construct.

The Company's proposed portfolio including full ownership of two nuclear units in 2022 and 2024 continues to be cost effective, but the Company recognizes the potential benefits to customers of securing new nuclear generation in smaller capacity increments through regional nuclear development. Duke Energy Carolinas' analysis indicates that the regional nuclear portfolio is lower cost to customers in the base case and most scenarios, but the full nuclear portfolio was chosen for the 2012 IRP preferred plan because there are no firm commitments in place at this time for the regional nuclear portfolio. Several advantages to a regional nuclear approach are:

- Load Growth: Smaller blocks of base load generation brought on-line over a period of years would more closely match projected load growth.
- Financial: The substantial capital cost would be phased in over a longer period of time and would spread the risk if there were cost increases.
- Regulatory Uncertainty: The optimal amount and timing of additional nuclear generation will depend on the outcome of final GHG legislation. Using a regional approach would allow utilities to better optimize their portfolios as legislation or regulation change over time.

Duke Energy Carolinas continues to support regional nuclear opportunities and is actively pursuing this concept. The Company will continue to assess opportunities to benefit from economies of scale and risk reduction by considering the prospects for joint ownership for new nuclear generation resources including potentially with Progress Energy Carolinas. As the Company announced in 2011 Duke Energy Carolinas has agreements with JEA, located in Jacksonville, Florida, and with the Public Service Authority of South Carolina (Santee Cooper). Duke Energy Carolinas has an agreement with Santee Cooper to perform due diligence to potentially acquire an option for a minority interest (5 to 10% of the capacity of the two units) in Santee Cooper's 45% ownership of the planned new nuclear reactors at V.C. Summer Nuclear Generating

[7] The CT/CC portfolio is more cost effective than the Nuclear portfolio by approximately $120 million.

Station in South Carolina. The new Summer units are scheduled to be online in 2017 and 2018. JEA has signed an option agreement to potentially purchase up to 20% of Lee Nuclear Station.

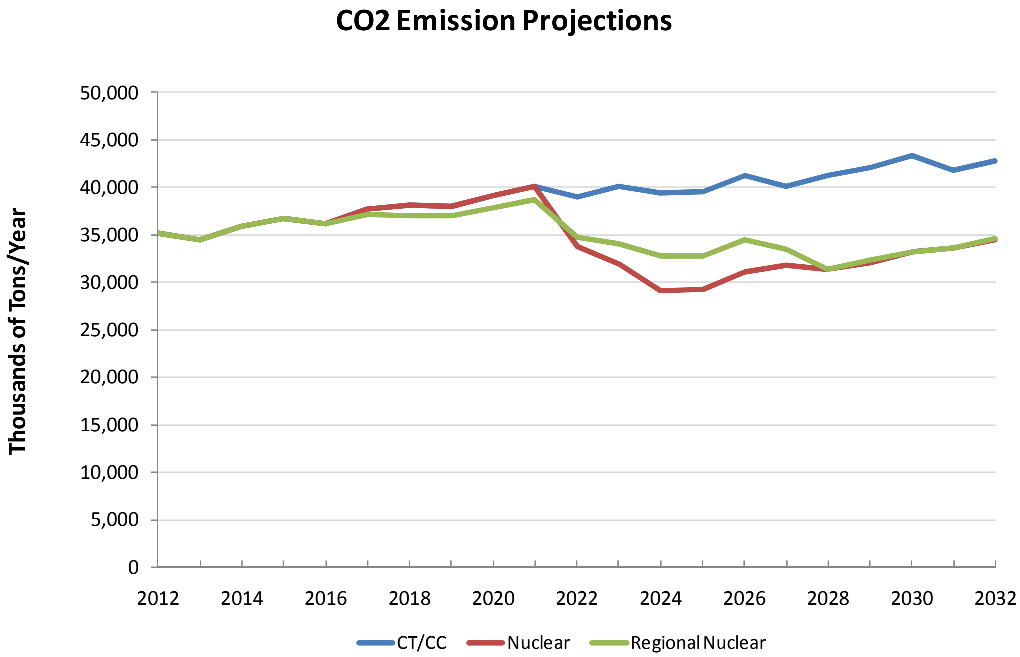
Although the Company believes it needs to plan for a carbon constrained future, a sensitivity analysis without a CO_2 emission price has been incorporated to show the relative impact of carbon on the nuclear and gas portfolios. In addition, a sensitivity analysis was also performed with higher fuel prices to reflect the impact fuel volatility can have on the portfolios without carbon prices. The lack of CO_2 prices significantly advantages the natural gas portfolio. However, as shown in Table A.2, the sensitivity analysis indicates that the addition of higher fuel prices to the no-carbon sensitivity reduces the value of the natural gas portfolio by approximately $3 billion PVRR.

The high nuclear capital cost sensitivity analysis reflects the importance of minimizing cost increases on the new nuclear generation. However, there is the risk that natural gas generation cost could also increase with the significant amount of natural gas generation that will be added over the planning horizon.

Quantitative Analysis Summary

One of the major benefits of having additional nuclear generation is the lower system CO_2 footprint and the associated economic benefit. The projected CO_2 emissions under the CT/CC, Nuclear, and Regional Nuclear scenarios are shown in Chart A.3 below. A review of these projections illustrates that for the Company to achieve material system reductions in CO_2 emissions, it must add new nuclear generation to the future resource portfolio. In the absence of a CO_2 policy, the CO_2 emissions in each portfolio would be at least two million tons higher by 2032.

Chart A.3 - CO_2 Emissions



The biggest risks to the proposed nuclear portfolios are the time required to license and construct a nuclear unit, uncertainty regarding GHG regulation/legislation, potential for lower demand than currently estimated, capital cost to build, and the ability to secure favorable financing. However, in a carbon constrained future, new nuclear generation must be in the generation mix to reduce the Company's carbon footprint. This is especially true as Oconee Nuclear Station nears the end of its licensed life in the 2030 timeframe.

In summary, the results of the quantitative analyses indicate that it is prudent for Duke Energy Carolinas to continue to preserve the option to build new nuclear capacity in the 2020 timeframe. The Company's analysis re-affirms the advantages of favorable financing and co-ownership in future nuclear generation. Duke Energy Carolinas is pursuing favorable financing options and continues to seek potential regional generation partners.

The overall conclusions of the quantitative analysis are that significant additions of base load, intermediate, peaking, EE, DSM, and renewable resources to the Duke Energy Carolinas portfolio are required over the planning horizon. Conclusions based on these analyses are:

- The new levels of EE and DSM are cost-effective for customers.
  - The screening analysis shows that portfolios with the new EE and DSM were lower cost than those without and EE and DSM.
  - The high EE sensitivity assumes 100% participation of cost effective EE programs identified in the 2011 Market Potential study. The high EE sensitivity is cost effective if there is an equal participation between residential and non-residential customers. If a significant number of non-residential customers opt out, then the high EE case may no longer be cost effective.
- Significant renewable resources will be needed to meet the new NC REPS and a potential federal standard.
- There is a capacity need in the 2016 to 2020 timeframe to maintain the target 15.5% reserve margin.
- The analysis demonstrates that the nuclear option is an attractive option for the Company's customers.
  - Continuing to preserve the option to secure new nuclear generation is prudent under the circumstances.
  - Favorable financing is very important to the project cost when compared to other generation options.
  - Co-ownership is beneficial from a generation and risk perspective.

For the purpose of demonstrating that there will be sufficient resources to meet customers' needs, Duke Energy Carolinas has selected a balanced portfolio which, over the 20-year planning horizon includes:

- 1,071 MW equivalent of incremental DSM capacity
- 135 MW of capacity from grid modernization impacts
- 1,320 MW of new EE (reduction to system peak load)
- 2,234 MW of new nuclear capacity
- 2,100 MW of new CC capacity
- 1,800 MW of new CT capacity
- 111 MW of nuclear uprates
- 758 MW of renewables (1,665 MWs nameplate)

Significant challenges remain with respect to the Company's portfolio, such as obtaining the necessary regulatory approvals to implement the EE and DSM programs and supply side resources, finding sufficient cost-effective, reliable renewable resources to meet the NC REPS standard, effectively integrating renewables into the resource mix, and ensuring sufficient transmission capability for these resources.

APPENDIX B

Duke Energy Carolinas Spring 2012 Forecast

Sales

Rates Billed

Peaks

2012-2027

Table of Contents

System Sales & System Peak Summer (2012 Spring Forecast vs. 2011 Spring Forecast)

System Sales is the sum of Retail and Wholesale. Retail Sales include Residential, Commercial, Industrial and Other Retail (Public Street Lighting & Traffic Signals). Wholesale Sales include contracts with municipals in Duke's service area as well as contracts with Piedmont, Blue Ridge , Rutherford, Haywood, NCEMC Retained, NCEMC Load Shape and New Horizon. The summer peak demand includes all loads that Duke Carolinas has a contractual obligation to serve, and thus includes System Sales plus Line losses and Company Use, and is after DSM has been subtraacted.

All sales & peaks given in this book are after the impacts of Duke Energy Carolinas sponsored energy efficiency (EE) programs have been subtracted.

Executive Summary

Growth Statistics from 2012 to 2013				
	Forecasted 2012	**Forecasted 2013**	**Growth**	
Item	**Amount**	**Amount**	**Amount**	**%**
System Sales	80,129 GWH	81,506 GWH	1,376 GWH	1.7%
System Summer Peak	17,716 MW	18,043 MW	327 MW	1.8%

Note: After Duke Energy Carolinas sponsored energy efficiency (EE) programs have been subtrac

System Sales Outlook for the Forecast Horizon (2011 – 2027)

System Sales for the Spring 2012 Forecast are projected to grow at an average annual rate of 1.5% from 2011 through 2027, which is less than the 1.7% in the Spring 2011 Forecast. The Spring 2012 Forecast for Residential, Commercial and Industrial is lower term than the Spring 2011 Forecast due to slower projected economic growth and the fact that actual sales in the latter part of 2011 were weaker than expected .

Adjustments were made to the Spring 2012 Forecasts and the Spring 2011 Forecasts to account for Duke Energy Carolinas Sponsored Energy Efficiency programs and the expected ban of incandescent lighting mandated by the Energy Independence and Security Act of 2007, as well as for the expected growth Plug-in Electric Vehicles. Additional adjustments to the Spring 2012 Forecast include sales reductions due to projected growth in Solar Energy.

Growth in the Wholesale is extremely strong from 2013-2019 due to the stair-step pattern of the contract with New Horizon beginning in 2013. By 2020 Duke Carolinas will supply 100% of their load.

Comparison of System Sales Growth Statistics Spring 2012 Forecast vs. Spring 2011 Forecast					
	Spring 2012 Forecast Annual Growth (2011-2027)		Spring 2011 Forecast Annual Growth (2011-2027)		Average Annual Difference
Item	**Amount**	**%**	**Amount**	**%**	
System Sales:					
Residential	308 GWH	1.0%	419 GWH	1.3%	-111 GWH
Commercial	558 GWH	1.8%	641 GWH	2.0%	-84 GWH
Industrial (total)	141 GWH	0.6%	159 GWH	0.7%	-18 GWH
Textile	-44 GWH	-1.2%	-36 GWH	-1.0%	-8 GWH
Other Industrial	184 GWH	1.0%	195 GWH	1.1%	-11 GWH
Other	5 GWH	1.5%	5 GWH	1.6%	0 GWH
Wholesale	369 GWH	5.1%	407 GWH	5.5%	-38 GWH
Total System	1,380 GWH	1.5%	1,632 GWH	1.7%	-252 GWH

Note: After Duke Energy Carolinas sponsored energy efficiency (EE) programs have been subtracted.

System Peak Outlook for the Forecast Horizon (2011 – 2027)

System peak hour demands are forecasted on a summer and winter basis. The peak forecast information below represents the amount of load that Duke Energy Carolinas is contractually obligated to serve and is used as the basis for Duke's Integrated Resource Plan.

The forecasts include an adjustment for proposed utility sponsored energy efficiency programs as well as adjustments for the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) and the proposed ban on incandescent lighting. The Spring 2012 Forecast also reflects the impacts of expected growth in solar energy.

The system summer peak demand on the Duke Energy Carolinas is expected to grow at an average annual rate of 1.7% from 2011 through 2027. The system peak winter demand is also expected to grow at an average annual rate of 1.7% from 2011 through 2027.

Comparison of System Peak Demand Growth Statistics Spring 2012 Forecast vs. Spring 2011 Forecast					
	Spring 2012 Forecast Annual Growth (2011-2027)		Spring 2011 Forecast Annual Growth (2011-2027)		Average Annual Difference [1]
Item	**Amount**	**%**	**Amount**	**%**	
System Peaks					
Summer	338 MW	1.7%	353 MW	1.8%	-14 MW
Winter	326 MW	1.7%	336 MW	1.8%	-10 MW

Note: After Duke Energy Carolinas sponsored energy efficiency (EE) programs have been subtracted.

(Load Forecast Pg 2)

General forecasting methodology for Duke Energy Carolinas energy and demand forecasts for Spring 2012

Duke Energy Carolinas' Spring 2012 forecasts represent projections of the energy and peak demand needs for its service area, which is located within the states of North and South Carolina, including the major urban areas of Charlotte, Greensboro and Winston-Salem in North Carolina and Spartanburg and Greenville in South Carolina. The forecasts cover the time period of 2012 – 2027 and represent the energy and peak demand needs for the Duke Energy Carolinas system comprised of the following customer classes and other utility/wholesale entities:

- Residential
- Commercial
- Textiles
- Other Industrial
- Other Retail
- Duke Energy Carolinas full/partial requirements wholesale

Energy use is dependent upon key economic factors such as income, energy prices and employment along with weather. The general framework of the Company's forecast methodology begins with forecasts of regional economic activity, demographic trends and expected long-term weather. The economic forecasts used in the Spring 2012 forecasts are obtained from Moody's Analytics, a nationally recognized economic forecasting firm, and include economic forecasts for the Duke Carolinas service area region. These economic forecasts represent long-term projections of numerous economic concepts including the following:

- Total real gross regional product (GRP)
- Non-manufacturing real GRP
- Non-manufacturing employment
- Manufacturing real GRP industry group, e.g., textiles
- Manufacturing Employment industry group
- Total real personal income

Total population forecasts are obtained from the two states' demographic offices for each county in each state which are then used to derive the total population forecast for the 51 counties that the Company serves in the Carolinas.

A projection of weather variables, cooling degree days (CDD) and heating degree days (HDD), is made for the forecast period by examining long-term historical weather. For the Spring 2012 forecasts, a 10 year simple average of CDD and HDD were used.

Other factors influencing the forecasts are identified and quantified such as changes in wholesale power contracts, historical billing days and other demographic trends including housing square footage, etc.

Energy forecasts for all of the Company's retail customers are developed at a customer class level, i.e., residential, commercial, textile, other industrial and street lighting along with forecasts for its wholesale customers. Econometric models incorporating the use of industry-standard linear regression techniques were developed utilizing a number of key drivers of energy usage as outlined above. The following provides information about the models.

Residential Class:
The Company's residential class sales forecast is comprised of two separate and independent forecasts. The first is the number of residential rates billed which is driven by population projections of the counties in which the Company provides electric service. The second forecast is energy usage per rate billed which is driven primarily by weather, regional economic and demographic trends, electric price and appliance efficiencies. The total residential sales forecast is derived by multiplying the two forecasts together.

Commercial Class:
Commercial electricity usage changes with the level of regional economic activity, such as personal income or commercial employment, and the impact of weather.

Textile Class:
The level of electricity consumption by Duke Energy Carolinas' textile group is impacted by the level of textile manufacturing output, exchange rates, electric prices and weather.

Other Industrial Class:
Electricity usage for Duke's other industrial customers was forecasted by 5 groups according to the 3 digit NAICS classification and then aggregated to provide the overall other industrial sales forecast. Usage is driven primarily by regional manufacturing output at a 3 digit NAICS level, industrial production indices, electric prices and weather.

Other Retail Class:
This class in comprised of public street lighting and traffic signals within the Company's service area. The level of electricity usage is impacted not only by economic growth but also by advances in lighting efficiencies.

Full / Partial Requirements Wholesale:
Duke Energy Carolinas provides electricity on a contract basis to numerous wholesale customers. The larger wholesale entities are forecasted by using an econometric model with aggregate economic drivers such as regional GDP or income. The very small entities are forecasted by assuming they grow at the same rate as Duke's retail sector. The Wholesale category is also affected by the terms of the contracted sales agreements and any changes therein.

Billed Sales and Other Energy Requirements

(Load Forecast Pg 5)

System Sales, which includes billed sales to Retail and Wholesale, are expected to grow at 1380 GWH per year or 1.5% over the forecast horizon. Retail sales include GWH sales billed to the Residential, Commercial, Industrial, Street and Public Lighting, and Traffic Signal Service classes. Full/Partial Requirements Wholesale sales include GWH sales billed to municipalities and public utility companies that purchase their full power requirements from the Company, plus in the forecast period, supplemental sales to specified EMCs in North Carolina and sales to the city of Greenwood, SC and sales to the Central Electric Power Cooperative, (New Horizon Contract).

Adjustments were made to the energy and peak projections for the Spring 2012 Forecast to reflect the effects of utility sponsored energy efficiency programs, and additions from the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) in the forecast. The expected ban on incandescent lighting mandated by the Energy Independence and Security Act of 2007 is reflected in the residential sales model by adjusting the appliance efficiency variable. Also, the expected reduction due to solar energy was included.

Points of Interest

• The **Residential** class continues to show positive growth, driven by steady gains in population within the Duke Energy Carolinas service area. The resulting annual growth in Residential billed sales is expected to average 1.0% over the forecast horizon.

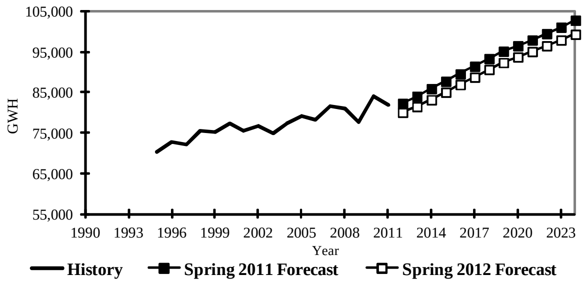
• The **Commercial** class is projected to be the fastest growing retail class, with billed sales growing at 1.8% per year over the next fifteen years. The three largest sectors in the Commercial Class are Offices, which includes banking, Retail and Education.

• The **Industrial** The long term structural decline that has occurred in the Textile industry is expected to moderate in the forecast horizon, with an overall projected decline of 1.2%, compared to an average decline of 6.9% from 1996-2011. In the Other Industrial sector, several industries such as Autos, Rubber & Plastics and Primary Metals, are projected to show strong growth. Overall, Other Industrial sales are expected to grow 1.0% over the forecast horizon.

• The **Full/Partial Requirements Wholesale** class is expected to grow at 5.1% annually over the forecast horizon, primarily due to the forecasted supplemental sales to specified EMCs in North Carolina and sales to New Horizons in South Carolina.

(Load Forecast Pg 6)

System Billed Sales ***(After EE Subtracted)*** *(Sum of Retail and Full/Partial Wholesale classes)*



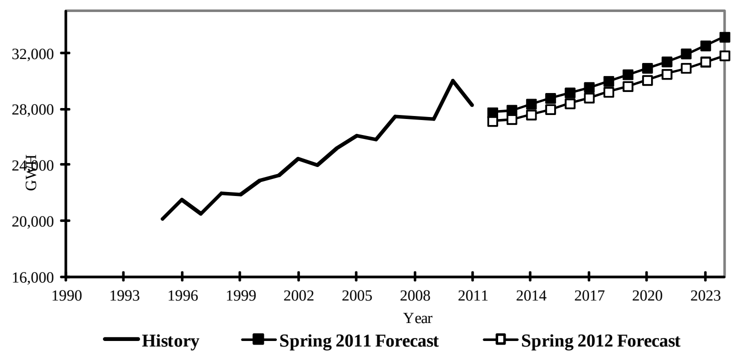
HISTORY / **AVERAGE ANNUAL GROWTH**

Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2002	76,769	1,164	1.5			
2003	74,784	-1,984	-2.6			
2004	77,374	2,590	3.5			
2005	79,130	1,756	2.3			
2006	78,347	-784	-1.0			
2007	81,572	3,225	4.1	History (2006 to 2011)	701	0.9
2008	81,066	-505	-0.6	History (1996 to 2011)	613	0.8
2009	77,528	-3,539	-4.4			
2010	84,088	6,561	8.5	Spring 2012 Forecast (2011 to 2027)	1380	1.5
2011	81,851	-2,237	-2.7	Spring 2011 Forecast (2011 to 2027)	1632	1.7

	SPRING 2012 FORECAST			SPRING 2011 FORECAST			SPRING 2012 vs SPRING 2011	
		Growth			Growth			
Year	GWH	GWH	%	GWH	GWH	%	GWH	%
2012	80,129	-1,722	-2.1	82,273	422	1.0	-2,144	-2.6%
2013	81,506	1,376	1.7	84,039	1,766	2.1	-2,534	-3.0%
2014	83,223	1,717	2.1	85,930	1,891	2.2	-2,708	-3.2%
2015	85,072	1,850	2.2	87,752	1,821	2.1	-2,679	-3.1%
2016	86,939	1,867	2.2	89,570	1,819	2.1	-2,631	-2.9%
2017	88,779	1,840	2.1	91,427	1,857	2.1	-2,648	-2.9%
2018	90,654	1,875	2.1	93,364	1,937	2.1	-2,710	-2.9%
2019	92,359	1,705	1.9	95,146	1,782	1.9	-2,787	-2.9%
2020	93,720	1,361	1.5	96,546	1,399	1.5	-2,826	-2.9%
2021	95,098	1,378	1.5	97,950	1,405	1.5	-2,852	-2.9%
2022	96,498	1,399	1.5	99,479	1,529	1.6	-2,981	-3.0%
2023	97,903	1,405	1.5	101,104	1,625	1.6	-3,202	-3.2%
2024	99,323	1,420	1.5	102,775	1,670	1.7	-3,452	-3.4%
2025	100,810	1,487	1.5	104,454	1,679	1.6	-3,644	-3.5%
2026	102,327	1,517	1.5	106,189	1,734	1.7	-3,862	-3.6%
2027	103,930	1,604	1.6	107,960	1,771	1.7	-4,029	-3.7%

(Load Forecast Pg 7)

Residential Billed Sales *(After EE Subtracted)*



HISTORY | **AVERAGE ANNUAL GROWTH**

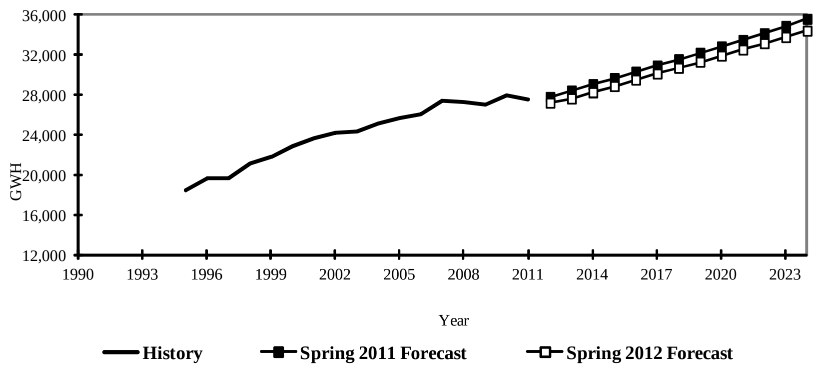
Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2002	24,466	1,194	5.1			
2003	23,947	-519	-2.1			
2004	25,150	1,203	5.0			
2005	26,108	958	3.8			
2006	25,816	-292	-1.1			
2007	27,459	1,643	6.4	History (2006 to 2011)	501	1.9
2008	27,335	-124	-0.5	History (1996 to 2011)	456	1.9
2009	27,273	-62	-0.2			
2010	30,049	2,777	10.2	Spring 2012 Forecast (2011 to 2027)	308	1.0
2011	28,323	-1,726	-5.7	Spring 2011 Forecast (2011 to 2027)	419	1.3

SPRING 2012 FORECAST | **SPRING 2011 FORECAST** | **SPRING 2012 vs SPRING 2011**

Year	GWH	Growth GWH	Growth %	GWH	Growth GWH	Growth %	GWH	%
2012	27,118	-1,205	-4.3	27,749	-574	1.0	-631	-2.3%
2013	27,252	134	0.5	27,914	165	0.6	-662	-2.4%
2014	27,584	332	1.2	28,350	436	1.6	-766	-2.7%
2015	27,974	390	1.4	28,760	410	1.4	-786	-2.7%
2016	28,391	417	1.5	29,154	394	1.4	-763	-2.6%
2017	28,796	405	1.4	29,554	400	1.4	-758	-2.6%
2018	29,209	414	1.4	29,995	441	1.5	-786	-2.6%
2019	29,623	413	1.4	30,454	459	1.5	-831	-2.7%
2020	30,056	433	1.5	30,926	472	1.5	-870	-2.8%
2021	30,490	434	1.4	31,387	461	1.5	-896	-2.9%
2022	30,930	439	1.4	31,946	559	1.8	-1,017	-3.2%
2023	31,369	440	1.4	32,535	589	1.8	-1,166	-3.6%
2024	31,826	456	1.5	33,154	619	1.9	-1,329	-4.0%
2025	32,296	470	1.5	33,774	620	1.9	-1,478	-4.4%
2026	32,758	462	1.4	34,408	634	1.9	-1,650	-4.8%
2027	33,243	485	1.5	35,021	614	1.8	-1,778	-5.1%

(Load Forecast Pg 8)

Commercial Billed Sales *(After EE Subtracted)*



HISTORY

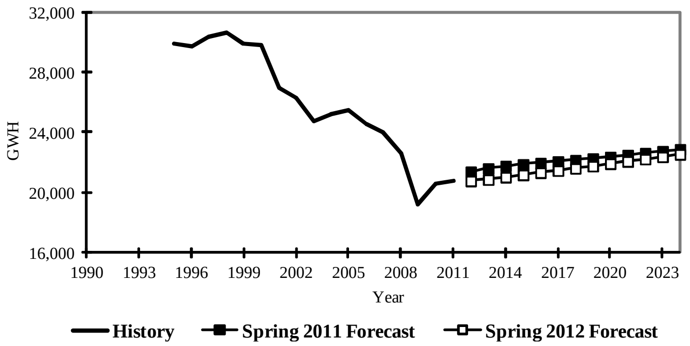
Year	Actual GWH	Growth GWH	Growth %
2002	24,242	576	2.4
2003	24,355	113	0.5
2004	25,204	849	3.5
2005	25,679	475	1.9
2006	26,030	352	1.4
2007	27,433	1,402	5.4
2008	27,288	-145	-0.5
2009	26,977	-311	-1.1
2010	27,968	991	3.7
2011	27,593	-375	-1.3

AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2006 to 2011)	312	1.2
History (1996 to 2011)	533	2.3
Spring 2012 Forecast (2011 to 2027)	558	1.8
Spring 2011 Forecast (2011 to 2027)	641	2.0

	SPRING 2012 FORECAST			**SPRING 2011 FORECAST**			**SPRING 2012 vs SPRING 2011**	
		Growth			Growth			
Year	GWH	GWH	%	GWH	GWH	%	GWH	%
2012	27,196	-397	-1.44	27,759	167	1.0	-564	-2.0%
2013	27,626	430	1.6	28,399	640	2.3	-773	-2.7%
2014	28,234	608	2.2	29,031	631	2.2	-796	-2.7%
2015	28,871	637	2.3	29,658	627	2.2	-787	-2.7%
2016	29,502	631	2.2	30,281	623	2.1	-779	-2.6%
2017	30,098	596	2.0	30,907	626	2.1	-809	-2.6%
2018	30,694	596	2.0	31,537	630	2.0	-843	-2.7%
2019	31,286	593	1.9	32,173	636	2.0	-886	-2.8%
2020	31,886	600	1.9	32,815	642	2.0	-928	-2.8%
2021	32,507	621	1.9	33,468	653	2.0	-960	-2.9%
2022	33,138	631	1.9	34,129	662	2.0	-991	-2.9%
2023	33,768	630	1.9	34,847	718	2.1	-1,079	-3.1%
2024	34,390	622	1.8	35,577	729	2.1	-1,187	-3.3%
2025	35,066	676	2.0	36,319	742	2.1	-1,252	-3.4%
2026	35,787	721	2.1	37,074	756	2.1	-1,287	-3.5%
2027	36,514	727	2.0	37,851	777	2.1	-1,337	-3.5%

Total Industrial Billed Sales *(After EE Subtracted)*



HISTORY | **AVERAGE ANNUAL GROWTH**

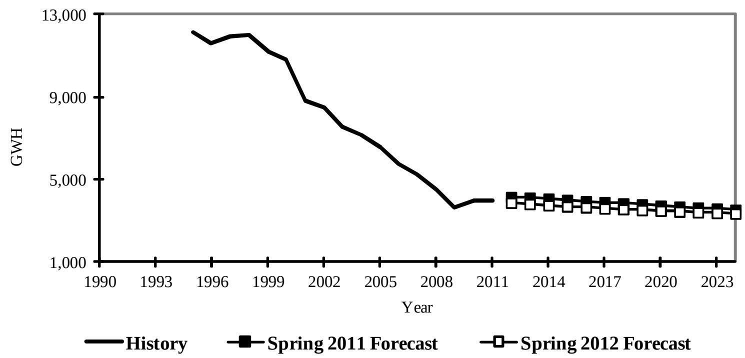
Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2002	26,259	-643	-2.4			
2003	24,764	-1,496	-5.7			
2004	25,209	445	1.8			
2005	25,495	286	1.1			
2006	24,535	-960	-3.8			
2007	23,948	-587	-2.4	History (2006 to 2011)	-750	-3.3
2008	22,634	-1,314	-5.5	History (1996 to 2011)	-597	-2.4
2009	19,204	-3,430	-15.2			
2010	20,618	1,414	7.4	Spring 2012 Forecast (2011 to 2027)	141	0.6
2011	20,783	164	0.8	Spring 2011 Forecast (2011 to 2027)	159	0.7

SPRING 2012 FORECAST | **SPRING 2011 FORECAST** | **SPRING 2012 vs SPRING 2011**

Year	GWH	Growth GWH	Growth %	GWH	Growth GWH	Growth %	GWH	%
2012	20,765	-17	-0.1	21,374	592	1.0	-609	-2.9%
2013	20,864	98	0.5	21,600	225	1.1	-736	-3.4%
2014	21,016	152	0.7	21,770	171	0.8	-755	-3.5%
2015	21,169	153	0.7	21,871	100	0.5	-702	-3.2%
2016	21,316	148	0.7	21,963	93	0.4	-647	-2.9%
2017	21,458	142	0.7	22,059	96	0.4	-601	-2.7%
2018	21,605	146	0.7	22,159	100	0.5	-555	-2.5%
2019	21,755	150	0.7	22,263	104	0.5	-508	-2.3%
2020	21,911	156	0.7	22,375	112	0.5	-464	-2.1%
2021	22,064	153	0.7	22,493	119	0.5	-429	-1.9%
2022	22,217	153	0.7	22,618	125	0.6	-402	-1.8%
2023	22,376	159	0.7	22,748	130	0.6	-373	-1.6%
2024	22,536	160	0.7	22,876	128	0.6	-340	-1.5%
2025	22,694	157	0.7	23,001	125	0.5	-308	-1.3%
2026	22,838	145	0.6	23,147	146	0.6	-309	-1.3%
2027	23,037	198	0.9	23,333	185	0.8	-296	-1.3%

(Load Forecast Pg 10)

Textile Billed Sales *(After EE Subtracted)*



HISTORY | **AVERAGE ANNUAL GROWTH**

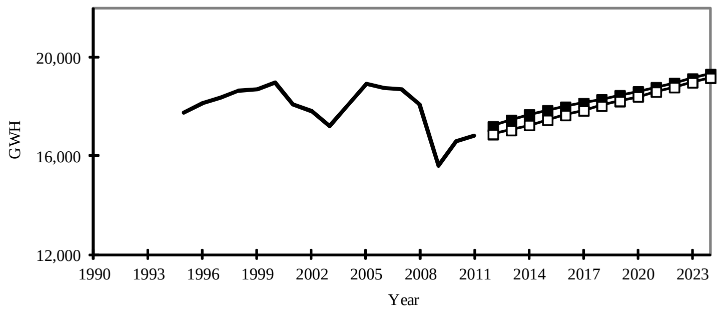
Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2002	8,443	-382	-4.3			
2003	7,562	-881	-10.4			
2004	7,147	-415	-5.5			
2005	6,561	-586	-8.2			
2006	5,791	-770	-11.7			
2007	5,224	-567	-9.8	History (2006 to 2011)	-362	-7.2
2008	4,524	-700	-13.4	History (1996 to 2011)	-508	-6.9
2009	3,616	-908	-20.1			
2010	4,003	387	10.7	Spring 2012 Forecast (2011 to 2027)	-44	-1.2
2011	3,983	-20	-0.5	Spring 2011 Forecast (2011 to 2027)	-36	-1.0

SPRING 2012 FORECAST | **SPRING 2011 FORECAST** | **SPRING 2012 vs SPRING 2011**

Year	Spring 2012 GWH	Growth GWH	Growth %	Spring 2011 GWH	Growth GWH	Growth %	2012 vs 2011 GWH	2012 vs 2011 %
2012	3,871	-112	-2.8	4,159	176	1.0	-288	-6.9%
2013	3,809	-61	-1.6	4,125	-33	-0.8	-316	-7.7%
2014	3,750	-60	-1.6	4,068	-57	-1.4	-318	-7.8%
2015	3,694	-55	-1.5	4,011	-57	-1.4	-316	-7.9%
2016	3,647	-47	-1.3	3,953	-57	-1.4	-306	-7.7%
2017	3,601	-46	-1.3	3,900	-54	-1.4	-298	-7.7%
2018	3,560	-42	-1.2	3,845	-54	-1.4	-286	-7.4%
2019	3,519	-41	-1.1	3,790	-55	-1.4	-271	-7.2%
2020	3,484	-35	-1.0	3,739	-51	-1.3	-255	-6.8%
2021	3,447	-38	-1.1	3,689	-51	-1.4	-242	-6.6%
2022	3,410	-37	-1.1	3,638	-51	-1.4	-228	-6.3%
2023	3,378	-32	-0.9	3,588	-50	-1.4	-210	-5.9%
2024	3,348	-30	-0.9	3,539	-49	-1.4	-191	-5.4%
2025	3,319	-29	-0.9	3,491	-48	-1.4	-171	-4.9%
2026	3,282	-37	-1.1	3,445	-45	-1.3	-164	-4.7%
2027	3,286	4	0.1	3,407	-39	-1.1	-121	-3.6%

(Load Forecast Pg 11)

Other Industrial Billed Sales *(Aftr EE Subtracted)*



HISTORY | **AVERAGE ANNUAL GROWTH**

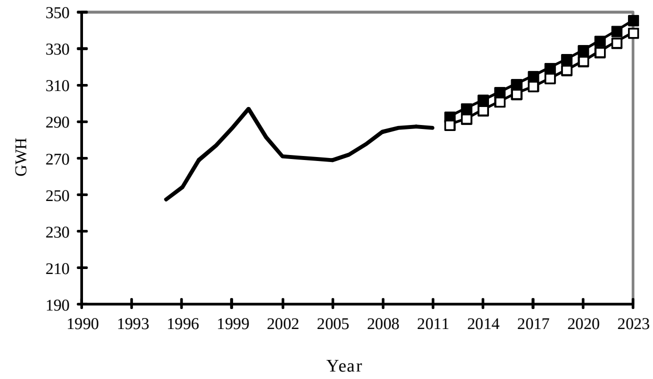
Year	Actual GWH	GWH	Growth %		GWH Per Year	% Per Year
2002	17,816	-261	-1.4			
2003	17,202	-614	-3.4			
2004	18,063	861	5.0			
2005	18,934	872	4.8			
2006	18,744	-191	-1.0			
2007	18,724	-20	-0.1	History (2006 to 2011)	-389	-2.2
2008	18,110	-614	-3.3	History (1996 to 2011)	-89	-0.5
2009	15,588	-2,522	-13.9			
2010	16,616	1,028	6.6	Spring 2012 Forecast (2011 to 2027)	184	1.0
2011	16,800	184	1.1	Spring 2011 Forecast (2011 to 2027)	195	1.1

SPRING 2012 FORECAST | **SPRING 2011 FORECAST** | **SPRING 2012 vs SPRING 2011**

Year	GWH	Growth GWH	Growth %	GWH	Growth GWH	Growth %	GWH	%
2012	16,894	94	0.6	17,216	416	1.0	-321	-1.9%
2013	17,054	160	0.9	17,474	259	1.5	-420	-2.4%
2014	17,266	212	1.2	17,702	228	1.3	-436	-2.5%
2015	17,474	208	1.2	17,860	158	0.9	-385	-2.2%
2016	17,669	195	1.1	18,010	150	0.8	-341	-1.9%
2017	17,857	188	1.1	18,159	150	0.8	-302	-1.7%
2018	18,045	188	1.1	18,314	154	0.8	-269	-1.5%
2019	18,236	191	1.1	18,473	159	0.9	-237	-1.3%
2020	18,427	191	1.0	18,635	162	0.9	-209	-1.1%
2021	18,617	191	1.0	18,805	169	0.9	-187	-1.0%
2022	18,807	190	1.0	18,981	176	0.9	-173	-0.9%
2023	18,998	191	1.0	19,160	180	0.9	-163	-0.8%
2024	19,188	190	1.0	19,337	177	0.9	-149	-0.8%
2025	19,374	186	1.0	19,510	173	0.9	-136	-0.7%
2026	19,556	182	0.9	19,702	192	1.0	-146	-0.7%
2027	19,751	194	1.0	19,926	224	1.1	-175	-0.9%

(Load Forecast Pg 12)

Other Retail Billed Sales *(Sum of PL, TS and Interdeptmental)*



HISTORY **AVERAGE ANNUAL GROWTH**

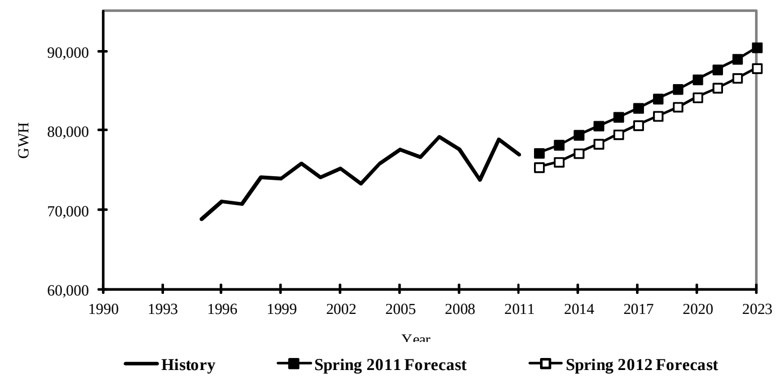
Year	Actual GWH	Growth GWH	Growth %		GWH Per Year	% Per Year
2007	278	6	2.4	History (2006 to 2011)	3	1.1
2008	284	6	2.2	History (1996 to 2011)	2	0.8
2009	287	3	0.9			
2010	287	1	0.2	Spring 2012 Forecast (2011 to 2027)	5	1.5
2011	287	0	-0.1	Spring 2011 Forecast (2011 to 2027)	5	1.6

SPRING 2012 FORECAST **SPRING 2011 FORECAST** **SPRING 2012 vs SPRING 2011**

Year	GWH	Growth GWH	Growth %	GWH	Growth GWH	Growth %	GWH	%
2012	288	1	0.5	293	6	1.0	-4	-1.5%
2013	292	3	1.2	297	5	1.6	-6	-1.9%
2014	296	5	1.6	302	5	1.6	-6	-1.9%
2015	301	5	1.6	306	4	1.4	-5	-1.7%
2016	305	4	1.4	310	4	1.4	-5	-1.7%
2017	309	4	1.4	315	4	1.4	-5	-1.7%
2018	314	4	1.4	319	4	1.4	-5	-1.7%
2019	318	4	1.4	324	5	1.5	-6	-1.8%
2020	323	5	1.5	329	5	1.5	-6	-1.8%
2021	328	5	1.5	334	5	1.5	-6	-1.8%
2022	333	5	1.6	340	5	1.6	-6	-1.9%
2023	339	5	1.6	346	6	1.7	-7	-2.0%
2024	345	6	1.7	352	6	1.8	-7	-2.0%
2025	351	6	1.8	358	6	1.8	-7	-2.0%
2026	357	6	1.8	364	6	1.8	-7	-2.0%
2027	363	6	1.8	371	7	1.8	-8	-2.0%

(Load Forecast Pg 13)

Retail Billed Sales *(After EE Subtracted)*



HISTORY

Year	Actual GWH	Growth GWH	Growth %
2007	79,118	2,466	3.2
2008	77,541	-1,577	-2.0
2009	73,740	-3,801	-4.9
2010	78,922	5,182	7.0
2011	76,985	-1,937	-2.5

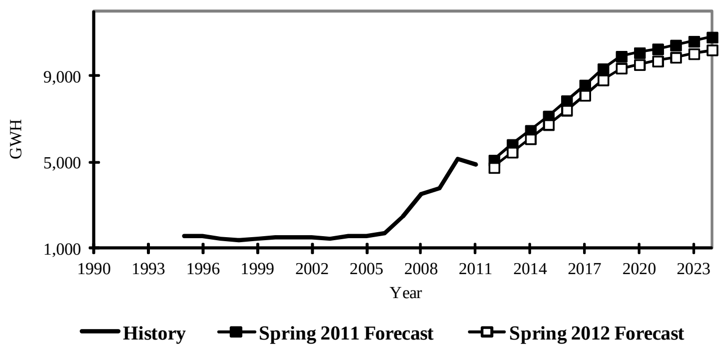
AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2006 to 2011)	67	0.1
History (1996 to 2011)	395	0.5
Spring 2012 Forecast (2011 to 2027)	1011	1.2
Spring 2011 Forecast (2011 to 2027)	1224	1.4

	SPRING 2012 FORECAST			SPRING 2011 FORECAST			SPRING 2012 vs SPRING 2011	
		Growth			Growth			
Year	GWH	GWH	%	GWH	GWH	%	GWH	%
2012	75,367	-1,618	-2.1	77,175	190	1.0	-1,809	-2.3%
2013	76,033	666	0.9	78,210	1,035	1.3	-2,178	-2.8%
2014	77,130	1,098	1.4	79,453	1,242	1.6	-2,322	-2.9%
2015	78,315	1,185	1.5	80,595	1,142	1.4	-2,279	-2.8%
2016	79,514	1,199	1.5	81,709	1,114	1.4	-2,194	-2.7%
2017	80,662	1,147	1.4	82,835	1,126	1.4	-2,173	-2.6%
2018	81,822	1,160	1.4	84,011	1,176	1.4	-2,189	-2.6%
2019	82,983	1,161	1.4	85,214	1,204	1.4	-2,232	-2.6%
2020	84,176	1,194	1.4	86,445	1,230	1.4	-2,268	-2.6%
2021	85,390	1,213	1.4	87,682	1,237	1.4	-2,292	-2.6%
2022	86,618	1,228	1.4	89,033	1,352	1.5	-2,416	-2.7%
2023	87,852	1,234	1.4	90,477	1,443	1.6	-2,625	-2.9%
2024	89,096	1,244	1.4	91,959	1,482	1.6	-2,862	-3.1%
2025	90,406	1,310	1.5	93,452	1,493	1.6	-3,046	-3.3%
2026	91,740	1,334	1.5	94,994	1,542	1.7	-3,253	-3.4%
2027	93,158	1,417	1.5	96,576	1,582	1.7	-3,418	-3.5%

(Load Forecast Pg 14)

Full / Partial Requirements Wholesale Billed Sales [1]



HISTORY

Year	Actual GWH	GWH	Growth %
2002	1,530	47	3.1
2003	1,448	-82	-5.4
2004	1,542	93	6.4
2005	1,580	38	2.5
2006	1,694	114	7.2
2007	2,454	760	44.8
2008	3,525	1,072	43.7
2009	3,788	262	7.4
2010	5,166	1,379	36.4
2011	4,866	-300	-5.8

AVERAGE ANNUAL GROWTH

	GWH Per Year	% Per Year
History (2006 to 2011)	634	23.5
History (1996 to 2011)	219	7.8
Spring 2012 Forecast (2011 to 2027)	369	5.1
Spring 2011 Forecast (2011 to 2027)	407	5.5

	SPRING 2012 FORECAST			SPRING 2011 FORECAST			SPRING 2012 vs SPRING 2011	
		Growth			Growth			
Year	GWH	GWH	%	GWH	GWH	%	GWH	%
2012	4,763	-103	-2.1	5,098	232	1.0	-335	-6.6%
2013	5,473	710	14.9	5,829	731	14.3	-356	-6.1%
2014	6,092	619	11.3	6,478	648	11.1	-385	-5.9%
2015	6,757	665	10.9	7,157	679	10.5	-400	-5.6%
2016	7,425	668	9.9	7,862	705	9.8	-437	-5.6%
2017	8,117	692	9.3	8,592	730	9.3	-475	-5.5%
2018	8,833	716	8.8	9,353	761	8.9	-521	-5.6%
2019	9,377	544	6.2	9,932	579	6.2	-555	-5.6%
2020	9,543	167	1.8	10,101	169	1.7	-557	-5.5%
2021	9,709	165	1.7	10,268	168	1.7	-560	-5.5%
2022	9,880	171	1.8	10,446	177	1.7	-566	-5.4%
2023	10,051	171	1.7	10,628	182	1.7	-577	-5.4%
2024	10,226	176	1.7	10,816	188	1.8	-590	-5.5%
2025	10,404	177	1.7	11,002	186	1.7	-599	-5.4%
2026	10,586	183	1.8	11,195	192	1.7	-608	-5.4%
2027	10,773	186	1.8	11,384	189	1.7	-611	-5.4%

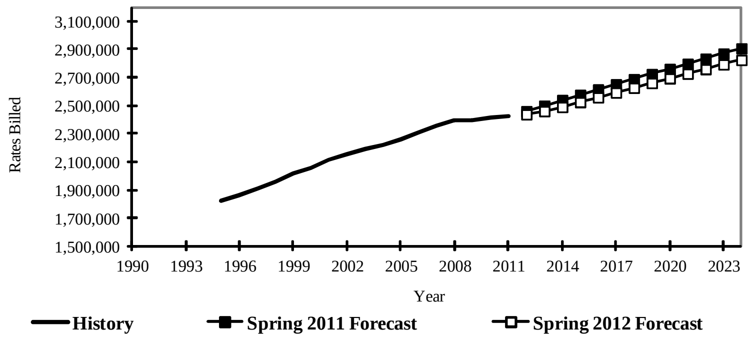
1 Does not include SEPA allocation.

Number of Rates Billed

(Load Forecast Pg 16)

Total Rates Billed

(Sum of Major Retail Classes: Residential, Commercial and Industrial)

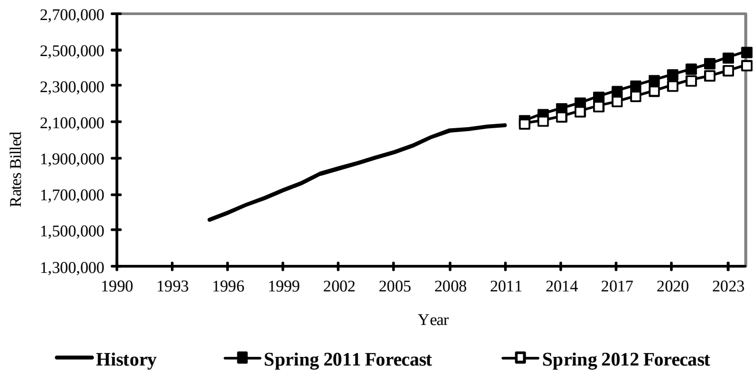


HISTORY				AVERAGE ANNUAL GROWTH		
Year	**Actual Rates Billed**	**Growth Rates Billed**	**%**		**Rates Billed Per Year**	**% Per Year**
2002	2,148,117	30,685	1.4			
2003	2,186,825	38,708	1.8			
2004	2,221,590	34,766	1.6			
2005	2,261,639	40,049	1.8			
2006	2,304,050	42,411	1.9			
2007	2,354,078	50,028	2.2	History (2006 to 2011)	24,064	1.0
2008	2,393,426	39,348	1.7	History (1996 to 2011)	37,416	1.8
2009	2,399,359	5,933	0.2			
2010	2,413,085	13,727	0.6	Spring 2012 Forecast (2011 to 2027)	31,347	1.2
2011	2,424,368	11,283	0.5	Spring 2011 Forecast (2011 to 2027)	-151,523	-100.0

SPRING 2012 FORECAST				SPRING 2011 FORECAST			SPRING 2012 vs SPRING 2011	
Year	**Rates Billed**	**Growth Rates Billed**	**%**	**Rates Billed**	**Growth Rates Billed**	**%**	**Rates Billed**	**%**
2012	2,438,779	14,411	0.6	2,461,853	37,485	1.0	-23,074	-0.9%
2013	2,461,153	22,374	0.9	2,500,751	38,899	1.6	-39,599	-1.6%
2014	2,490,608	29,455	1.2	2,539,624	38,872	1.6	-49,016	-1.9%
2015	2,525,184	34,576	1.4	2,577,453	37,829	1.5	-52,269	-2.0%
2016	2,559,552	34,369	1.4	2,614,490	37,037	1.4	-54,937	-2.1%
2017	2,593,628	34,076	1.3	2,651,397	36,907	1.4	-57,769	-2.2%
2018	2,627,486	33,858	1.3	2,688,220	36,823	1.4	-60,734	-2.3%
2019	2,660,526	33,040	1.3	2,724,824	36,604	1.4	-64,298	-2.4%
2020	2,693,885	33,359	1.3	2,761,410	36,586	1.3	-67,525	-2.4%
2021	2,727,342	33,457	1.2	2,798,003	36,593	1.3	-70,661	-2.5%
2022	2,760,168	32,825	1.2	2,834,602	36,599	1.3	-74,434	-2.6%
2023	2,792,602	32,434	1.2	2,871,206	36,604	1.3	-78,604	-2.7%
2024	2,825,550	32,948	1.2	2,907,812	36,606	1.3	-82,262	-2.8%
2025	2,858,888	33,338	1.2	2,944,418	36,606	1.3	-85,530	-2.9%
2026	2,892,410	33,522	1.2	2,980,922	36,504	1.2	-88,512	-3.0%
2027	2,925,912	33,503	1.2					

(Load Forecast Pg 17)

Residential Rates Billed



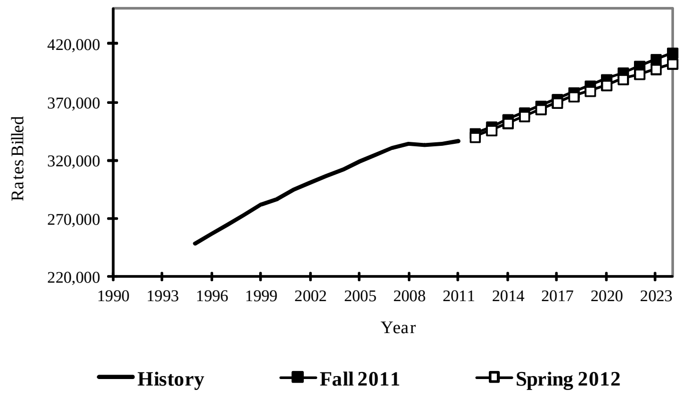
HISTORY | **AVERAGE ANNUAL GROWTH**

Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2002	1,839,689	25,822	1.4			
2003	1,872,484	32,795	1.8			
2004	1,901,335	28,851	1.5			
2005	1,935,320	33,985	1.8			
2006	1,971,673	36,353	1.9			
2007	2,016,104	44,431	2.3	History (2006 to 2011)	21,901	1.1
2008	2,052,252	36,149	1.8	History (1996 to 2011)	32,184	1.8
2009	2,059,394	7,142	0.3			
2010	2,071,877	12,484	0.6	Spring 2012 Forecast (2011 to 2027)	26,168	1.2
2011	2,081,179	9,302	0.4	Spring 2011 Forecast (2011 to 2027)	31,234	1.4

SPRING 2012 FORECAST				SPRING 2011 FORECAST			SPRING 2012 vs SPRING 2011	
Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Growth Rates Billed	%	Rates Billed	%
2012	2,091,635	10,456	0.5	2,111,339	30,161	1.0	-19,705	-0.9%
2013	2,108,208	16,573	0.8	2,144,532	33,193	1.6	-36,324	-1.7%
2014	2,131,555	23,347	1.1	2,177,288	32,756	1.5	-45,733	-2.1%
2015	2,160,074	28,519	1.3	2,209,204	31,915	1.5	-49,129	-2.2%
2016	2,188,612	28,537	1.3	2,240,467	31,263	1.4	-51,855	-2.3%
2017	2,217,078	28,466	1.3	2,271,658	31,192	1.4	-54,581	-2.4%
2018	2,245,525	28,447	1.3	2,302,781	31,122	1.4	-57,256	-2.5%
2019	2,273,922	28,398	1.3	2,333,700	30,919	1.3	-59,777	-2.6%
2020	2,302,301	28,378	1.2	2,364,617	30,918	1.3	-62,316	-2.6%
2021	2,330,644	28,343	1.2	2,395,539	30,922	1.3	-64,895	-2.7%
2022	2,358,961	28,317	1.2	2,426,465	30,925	1.3	-67,503	-2.8%
2023	2,387,255	28,294	1.2	2,457,395	30,931	1.3	-70,140	-2.9%
2024	2,415,522	28,267	1.2	2,488,332	30,937	1.3	-72,810	-2.9%
2025	2,443,766	28,243	1.2	2,519,270	30,939	1.2	-75,505	-3.0%
2026	2,471,824	28,059	1.1	2,550,110	30,840	1.2	-78,286	-3.1%
2027	2,499,864	28,040	1.1					

(Load Forecast Pg 18)

Commercial Rates Billed

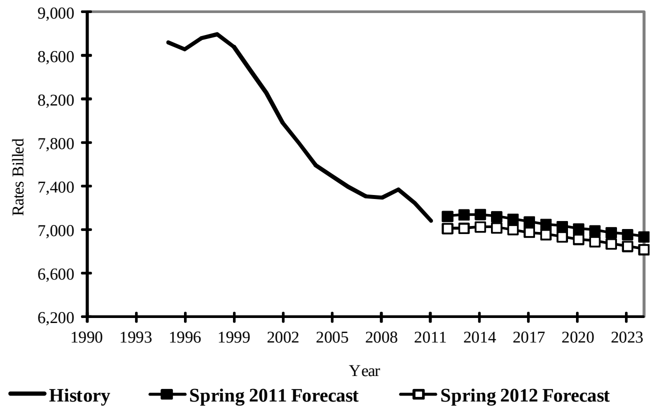


HISTORY				AVERAGE ANNUAL GROWTH		
Year	**Actual Rates Billed**	**Growth Rates Billed**	**%**		**Rates Billed Per Year**	**% Per Year**
2002	300,440	5,140	1.7			
2003	306,540	6,101	2.0			
2004	312,665	6,125	2.0			
2005	318,827	6,162	2.0			
2006	324,977	6,150	1.9			
2007	330,666	5,689	1.8	History (2006 to 2011)	2,224	0.7
2008	333,873	3,208	1.0	History (1996 to 2011)	5,337	1.8
2009	332,593	-1,280	-0.4			
2010	333,960	1,367	0.4	Spring 2012 Forecast (2011 to 2027)	5,197	1.4
2011	336,099	2,139	0.6	Spring 2011 Forecast (2011 to 2027)	5,844	1.5

SPRING 2012 FORECAST				SPRING 2011 FORECAST			SPRING 2012 vs SPRING 2011	
Year	**Rates Billed**	**Growth Rates Billed**	**%**	**Rates Billed**	**Growth Rates Billed**	**%**	**Rates Billed**	**%**
2011	340,127	4,028	1.2	343,384	7,285	1.0	-3,257	-0.9%
2013	345,925	5,798	1.7	349,077	5,693	1.7	-3,152	-0.9%
2014	352,020	6,095	1.8	355,189	6,112	1.8	-3,170	-0.9%
2015	358,086	6,066	1.7	361,123	5,934	1.7	-3,038	-0.8%
2016	363,933	5,847	1.6	366,919	5,795	1.6	-2,986	-0.8%
2017	369,567	5,634	1.5	372,660	5,741	1.6	-3,093	-0.8%
2018	374,999	5,433	1.5	378,382	5,722	1.5	-3,383	-0.9%
2019	379,662	4,663	1.2	384,087	5,705	1.5	-4,425	-1.2%
2020	384,665	5,003	1.3	389,777	5,690	1.5	-5,111	-1.3%
2021	389,801	5,135	1.3	395,466	5,690	1.5	-5,666	-1.4%
2022	394,329	4,528	1.2	401,157	5,690	1.4	-6,828	-1.7%
2023	398,492	4,163	1.1	406,848	5,691	1.4	-8,356	-2.1%
2024	403,203	4,711	1.2	412,539	5,692	1.4	-9,336	-2.3%
2025	408,322	5,118	1.3	418,232	5,693	1.4	-9,911	-2.4%
2026	413,784	5,463	1.3	423,917	5,685	1.4	-10,133	-2.4%
2027	419,247	5,463	1.3					

(Load Forecast Pg 19)

Total Industrial Rates Billed *(Includes Textile and Other Industrial)*



HISTORY **AVERAGE ANNUAL GROWTH**

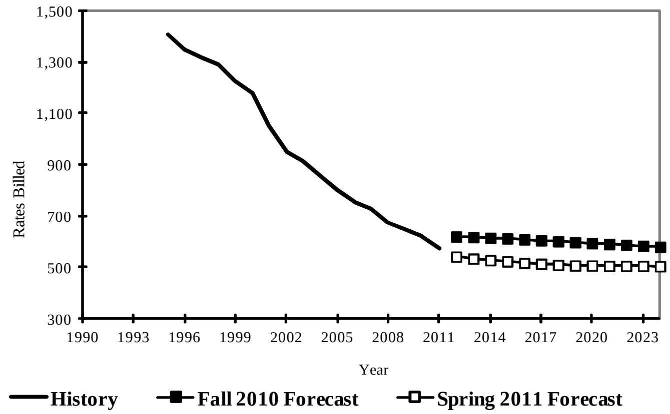
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2002	7,989	-276	-3.3			
2003	7,801	-188	-2.3			
2004	7,591	-210	-2.7			
2005	7,492	-99	-1.3			
2006	7,401	-91	-1.2			
2007	7,309	-92	-1.2	History (2006 to 2011)	-62	-0.9
2008	7,301	-8	-0.1	History (1996 to 2011)	-105	-1.3
2009	7,372	71	1.0			
2010	7,248	-124	-1.7	Spring 2012 Forecast (2011 to 2027)	-18	-0.3
2011	7,090	-158	-2.2	Spring 2011 Forecast (2011 to 2027)	-443	-100.0

SPRING 2012 FORECAST **SPRING 2011 FORECAST** **SPRING 2012 vs SPRING 2011**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Growth Rates Billed	%	Rates Billed	%
2012	7,017	-73	-1.0	7,130	39	1.0	-112	-1.6%
2013	7,020	3	0.0	7,143	13	0.2	-123	-1.7%
2014	7,033	13	0.2	7,146	3	0.0	-114	-1.6%
2015	7,024	-9	-0.1	7,126	-20	-0.3	-102	-1.4%
2016	7,008	-16	-0.2	7,104	-22	-0.3	-97	-1.4%
2017	6,984	-24	-0.3	7,079	-26	-0.4	-95	-1.3%
2018	6,962	-22	-0.3	7,057	-21	-0.3	-95	-1.3%
2019	6,942	-21	-0.3	7,037	-20	-0.3	-96	-1.4%
2020	6,919	-23	-0.3	7,016	-21	-0.3	-97	-1.4%
2021	6,897	-21	-0.3	6,997	-19	-0.3	-100	-1.4%
2022	6,878	-20	-0.3	6,981	-17	-0.2	-103	-1.5%
2023	6,855	-23	-0.3	6,963	-18	-0.3	-108	-1.6%
2024	6,825	-30	-0.4	6,941	-22	-0.3	-116	-1.7%
2025	6,801	-24	-0.4	6,915	-26	-0.4	-114	-1.7%
2026	6,801	0	0.0	6,894	-22	-0.3	-93	-1.3%
2027	6,801	0	0.0					

(Load Forecast Pg 20)

Textile Rates Billed



HISTORY **AVERAGE ANNUAL GROWTH**

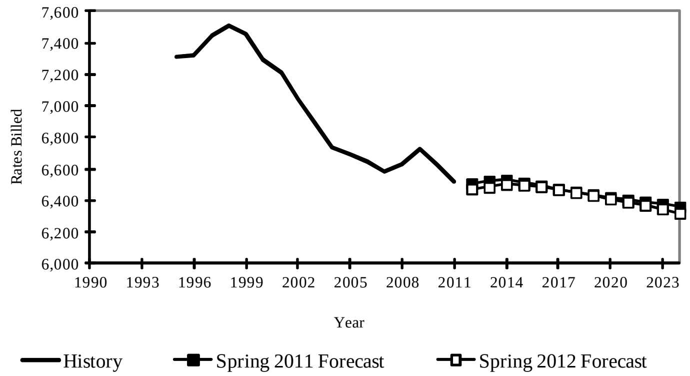
Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2002	949	-103	-9.8			
2003	914	-35	-3.6			
2004	857	-57	-6.2			
2005	802	-56	-6.5			
2006	757	-45	-5.6			
2007	728	-29	-3.8	History (2006 to 2011)	-37	-5.5
2008	675	-53	-7.3	History (1996 to 2011)	-52	-5.6
2009	649	-26	-3.9			
2010	622	-27	-4.2	Spring 2012 Forecast (2011 to 2027)	-4	-0.7
2011	572	-50	-8.1	Spring 2011 Forecast (2011 to 2027)	0	0.0

SPRING 2012 FORECAST **SPRING 2011 FORECAST** **SPRING 2012 vs SPRING 2011**

Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Growth Rates Billed	%	Rates Billed	%
2011	543	-29	-5.0	621	49	1.1	-78	-12.5%
2013	535	-8	-1.5	618	-2	-0.4	-83	-13.5%
2014	529	-6	-1.1	616	-2	-0.4	-87	-14.1%
2015	524	-5	-0.9	613	-3	-0.5	-89	-14.5%
2016	518	-6	-1.2	609	-4	-0.6	-91	-14.9%
2017	514	-4	-0.7	606	-3	-0.6	-91	-15.1%
2018	511	-4	-0.8	602	-3	-0.6	-92	-15.2%
2019	508	-2	-0.5	599	-4	-0.6	-91	-15.1%
2020	508	0	-0.1	595	-3	-0.6	-87	-14.7%
2021	507	-1	-0.2	592	-3	-0.6	-85	-14.4%
2022	506	-1	-0.1	588	-4	-0.6	-82	-14.0%
2023	507	0	0.1	585	-4	-0.7	-78	-13.3%
2024	505	-2	-0.3	581	-4	-0.7	-76	-13.0%
2025	504	-1	-0.2	576	-5	-0.8	-72	-12.5%
2026	506	1	0.3	573	-3	-0.6	-67	-11.7%
2027	507	1	0.3					

(Load Forecast Pg 21)

Other Industrial Rates Billed



HISTORY **AVERAGE ANNUAL GROWTH**

Year	Actual Rates Billed	Growth Rates Billed	%		Rates Billed Per Year	% Per Year
2002	7,040	-173	-2.4			
2003	6,887	-153	-2.2			
2004	6,733	-154	-2.2			
2005	6,690	-43	-0.6			
2006	6,644	-47	-0.7			
2007	6,581	-63	-0.9	History (2006 to 2011)	-25	-0.4
2008	6,626	45	0.7	History (1996 to 2011)	-53	-0.8
2009	6,723	97	1.5			
2010	6,626	-97	-1.4	Spring 2012 Forecast (2011 to 2027)	-14	-0.2
2011	6,518	-108	-1.6	Spring 2011 Forecast (2011 to 2027)	-13	-0.2

SPRING 2012 FORECAST				SPRING 2011 FORECAST			SPRING 2012 vs SPRING 2011	
Year	Rates Billed	Growth Rates Billed	%	Rates Billed	Growth Rates Billed	%	Rates Billed	%
2012	6,474	-44	-0.7	6,509	-9	1.0	-34	-0.5%
2013	6,485	10	0.2	6,524	15	0.2	-39	-0.6%
2014	6,503	19	0.3	6,530	6	0.1	-27	-0.4%
2015	6,499	-4	-0.1	6,513	-17	-0.3	-14	-0.2%
2016	6,490	-10	-0.1	6,495	-18	-0.3	-6	-0.1%
2017	6,470	-20	-0.3	6,473	-22	-0.3	-3	-0.1%
2018	6,452	-18	-0.3	6,455	-18	-0.3	-3	-0.1%
2019	6,433	-18	-0.3	6,438	-17	-0.3	-5	-0.1%
2020	6,411	-23	-0.4	6,420	-18	-0.3	-10	-0.2%
2021	6,391	-20	-0.3	6,405	-15	-0.2	-15	-0.2%
2022	6,371	-19	-0.3	6,392	-13	-0.2	-21	-0.3%
2023	6,348	-23	-0.4	6,378	-14	-0.2	-30	-0.5%
2024	6,320	-28	-0.4	6,360	-18	-0.3	-40	-0.6%
2025	6,297	-23	-0.4	6,339	-21	-0.3	-42	-0.7%
2026	6,295	-1	0.0	6,321	-18	-0.3	-26	-0.4%
2027	6,294	-1	0.0	6,303	-9	-0.1	-18	

(Load Forecast Pg 22)

System Peaks

(Load Forecast Pg 23)

The Summer peak forecast represents the maximum demand during the summer season on the Duke Energy Carolinas system. The Summer Peak Forecast includes all load that Duke Energy Carolinas is contractually obligated to serve and is used in the Integrated Resource Plan. It includes all Retail classes, Wholesale, Company Use and is at generation.

The forecast reflects Duke Energy Carolinas energy efficiency programs as well as adjustments for the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) and the proposed ban on incandescent lighting. The Spring 2012 Forecast also reflects the impacts of expected growth in solar energy.

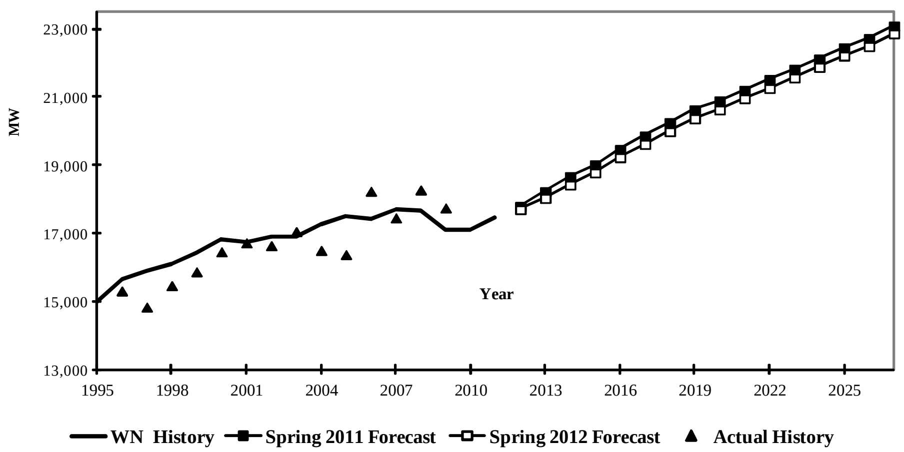
Thus, the Summer Peak forecast shown is after all adjustments.

Growth Forecasts

The new forecast projects an incremental growth of 338 MW or 1.7% per year for 2011-2027. The previous forecast growth was 353 MW or 1.8% per year for 2011-2027.

(Load Forecast Pg 24)

Native Load Summer MW ***(After EE Subtracted)***



WEATHER NORMAL HISTORY — **AVERAGE ANNUAL GROWTH**

Year	MW	Growth MW	Growth %		MW Per Year	% Per Year	Actual MW
2005	17,497						16,399
2006	17,439	-58	-0.3				18,255
2007	17,698	259	1.5	History (2006 to 2011)	4	0.0	17,474
2008	17,670	-28	-0.2	History (1996 to 2011)	120	0.7	18,292
2009	17,100	-570	-3.2				17,760
2010	17,088	-12	-0.1	Spring 2012 Forecast (2011 to 2027)	338	1.7	17,358
2011	17,457	369	2.2	Spring 2011 Forecast (2011 to 2027)	353	1.8	17,772

SPRING 2012 FORECAST — **SPRING 2011 FORECAST** — **2012 vs SPRING 2011**

Year	MW	Growth MW	Growth %	MW	Growth MW	Growth %	MW	%
2012	17,716	259	1.5	17,812	355	1.0	-96	-0.5%
2013	18,043	327	1.8	18,245	433	2.4	-202	-1.1%
2014	18,437	393	2.2	18,680	435	2.4	-243	-1.3%
2015	18,795	358	1.9	19,032	352	1.9	-237	-1.2%
2016	19,239	444	2.4	19,476	444	2.3	-237	-1.2%
2017	19,630	391	2.0	19,877	401	2.1	-247	-1.2%
2018	20,002	372	1.9	20,265	388	2.0	-263	-1.3%
2019	20,379	377	1.9	20,644	379	1.9	-265	-1.3%
2020	20,638	259	1.3	20,901	257	1.2	-263	-1.3%
2021	20,967	328	1.6	21,214	313	1.5	-247	-1.2%
2022	21,268	301	1.4	21,530	316	1.5	-262	-1.2%
2023	21,577	309	1.5	21,836	306	1.4	-259	-1.2%
2024	21,888	311	1.4	22,135	299	1.4	-247	-1.1%
2025	22,219	331	1.5	22,465	330	1.5	-245	-1.1%
2026	22,499	279	1.3	22,733	268	1.2	-234	-1.0%
2027	22,871	372	1.7	23,099	366	1.6	-228	-1.0%

(Load Forecast Pg 25)

The Winter peak forecast represents the maximum demand during the winter season on the Duke Energy Carolinas' system. The Winter Peak Forecast includes all load that Duke Energy Carolinas is contractually obligated to serve and is used in the Integrated Resource Plan. It includes all Retail classes, Wholesale, Company Use and is at generation.

The forecast reflects Duke Energy Carolinas sponsored energy efficiency programs as well as adjustments for the expected growth in Plug-in Hybrid Electric Vehicles (PHEV) and the proposed ban on incandescent lighting. The Spring 2012 Forecast also reflects the impacts of expected growth in solar energy.
Thus, the Winter Peak forecast shown is after all adjustments.

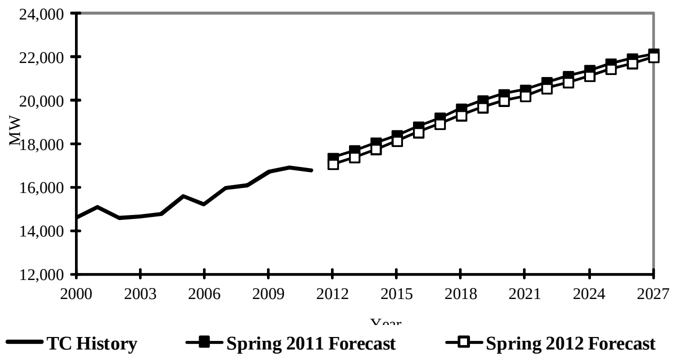
Winter Peak

Growth Forecasts

The new Forecast projects an incremental growth of 326 MW or 1.7% per year from 2011-2027. The previous forecast growth was 336 MW or 1.8% per year from 2011-2027.

(Load Forecast Pg 26)

System Winter MW *(After EE Subtracted)*



WEATHER NORMAL
HISTORY

Year	MW	Growth MW	Growth %
2002	14,565	-506	-3.4
2003	14,626	61	0.4
2004	14,770	144	1.0
2005	15,568	798	5.4
2006	15,193	-375	-2.4
2007	15,936	742	4.9
2008	16,065	130	0.8
2009	16,723	657	4.1
2010	16,893	170	1.0
2011	16,774	-119	-0.7

AVERAGE ANNUAL GROWTH

	MW Per Year	% Per Year
History (2006 to 2011)	316	2.0
History (2000 to 2011)	199	1.3
Spring 2012 Forecast (2011 to 2027)	326	1.7
Spring 2011 Forecast (2011 to 2027)	336	1.8

SPRING 2012 FORECAST | **SPRING 2011 FORECAST** | **2012 vs SPRING 2011**

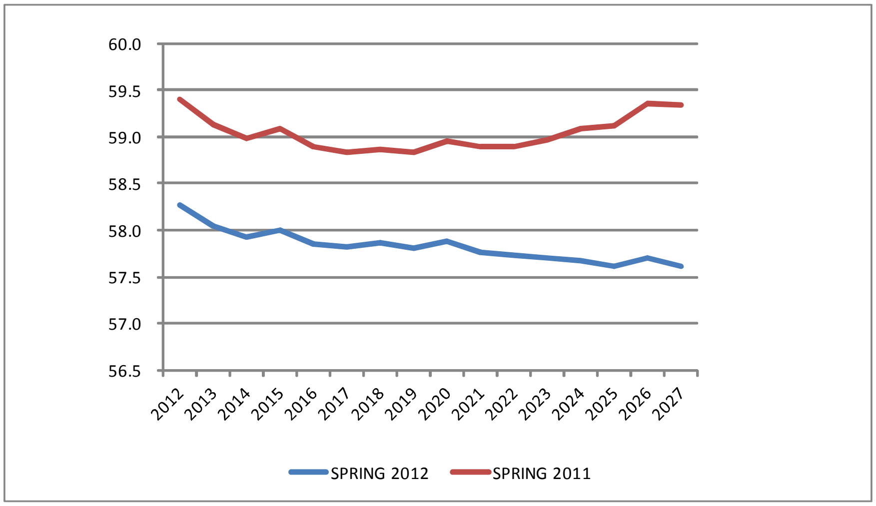
Year	MW	Growth MW	Growth %	MW	Growth MW	Growth %	MW	%
2012	17,069	295	1.8	17,348	574	1.0	-279	-1.6%
2013	17,383	314	1.8	17,695	347	2.0	-311	-1.8%
2014	17,759	375	2.2	18,044	350	2.0	-286	-1.6%
2015	18,130	372	2.1	18,388	343	1.9	-257	-1.4%
2016	18,526	395	2.2	18,790	402	2.2	-264	-1.4%
2017	18,921	395	2.1	19,201	411	2.2	-280	-1.5%
2018	19,303	382	2.0	19,608	407	2.1	-305	-1.6%
2019	19,677	374	1.9	19,985	377	1.9	-309	-1.5%
2020	19,985	309	1.6	20,279	294	1.5	-294	-1.4%
2021	20,197	211	1.1	20,476	197	1.0	-279	-1.4%
2022	20,546	349	1.7	20,831	355	1.7	-285	-1.4%
2023	20,828	282	1.4	21,101	271	1.3	-273	-1.3%
2024	21,117	289	1.4	21,386	284	1.3	-268	-1.3%
2025	21,446	328	1.6	21,679	293	1.4	-233	-1.1%
2026	21,706	260	1.2	21,920	241	1.1	-214	-1.0%
2027	21,994	289	1.3	22,148	228	1.0	-153	-0.7%

(Load Forecast Pg 27)

Summer Load Factor (After EE Subtracted)

The Load factor below is based on the IRP load. The system load factor represents the relationship between annual energy and the maximum demand for the Duke Energy Carolinas' system. It is measured at generation level and is reflects sales and peaks after all EE, EV and PV programs have been subtracted..

Load Factor



Year	SPRING 2012 Load Factor	SPRING 2011 Load Factor
2012	58.3	59.4
2013	58.0	59.1
2014	57.9	59.0
2015	58.0	59.1
2016	57.8	58.9
2017	57.8	58.8
2018	57.9	58.9
2019	57.8	58.8
2020	57.9	59.0
2021	57.8	58.9
2022	57.7	58.9
2023	57.7	59.0
2024	57.7	59.1
2025	57.6	59.1
2026	57.7	59.4
2027	57.6	59.3

(Load Forecast Pg 28)

Load Definitions

The following table shows differences in the load forecasts that are utilized for various Company and regulatory documents, reports, and filings.

LOAD TYPES/ LOAD COMPONENTS	BALANCING AUTHORITY	IRP	RPO	FERC FORM1	SERC	LOAD FORECAST BOOK	REGULAR BILLED SALES	TRANSMISSION
RETAIL	X	X	X	X	X	X	X	X
S10A - CONCORD	X	X	X	X	X	X	X	X
S10A - DALLAS	X	X	X	X	X	X	X	X
S10A - KINGS MOUNTAIN	X	X	X	X	X	X	X	X
S10A - FOREST CITY	X	X	X	X	X	X	X	X
S10A - DUE WEST	X	X	X	X	X	X	X	X
S10A - PROSPERITY	X	X	X	X	X	X	X	X
S10A - LOCKHART	X	X	X	X	X	X	X	X
WESTERN CAROLINA UNIVERSTIY	X	X	X	X	X	X	X	X
HIGHLAND	X	X	X	X	X	X	X	X
GREENWOOD	X	X	X	X		X	X	X
SENECA	X							X
SCEG	X							X
PIEDMONT EMC		X	X	X			X	
BLUE RIDGE EMC		X	X	X			X	
RUTHERFORD EMC		X	X	X			X	
HAYWOOD EMC		X	X	X			X	
NCEMC TOTAL	X					X		X
NCMPA TOTAL	X					X		X
PMPA TOTAL	X					X		X
SALUDA RIVER TOTAL						X		X
NCEMC OWNERSHIP OF CATAWBA NET OF PBRH CATAWBA (630-98-3)		X	X					
NCEMC FIXED LOAD SHAPE		X		X			X	
NEW HORIZON STEP-UP CONTRACT	X (Start in 2013)	X (Start in 2013)	X (Start in 2013)	X (Start in 2013)	X (Start in 2013)		X (Start in 2013)	
LINE LOSSES	X	X	X	X	X	X		X
UNBILLED	X	X	X	X	X	X		X
COMPANY USE	X	X	X	X	X	X		X

Notes:

This table serves a reference for developing forecast for various load definitions. Because historical load for different load definitions are derived from the balancing autority load, please refers to the Load Calculation page for the equations used to come up with historical load actuals.

1. Changes from 2011 definition

1) NCEMC's ownership reduced from 682 to 630 because they are moving 52 MWs of their entitlement to PJM (off-system)

2) Remove 432 NCMPA entitlement, backstand agreement ends Dec 31, 2011

2. Greenwood became part of Duke's native load for IRP and RPO beginning Jan 1st 2010.

3. Seneca was added to Balancing Authority load on July 14 2010 @ HE 1000.

4. The loss multiplier to convert meter load to generation is 1.03092783505155

5. New Horizon co-ops include Little River EC, Blue Ridge EC, Broad River EC, York EC and Laurens EC.

generation (SEPA and BTM). The engineering definition of BA load is: Sum of Duke's Generation + Load Flowing in + Load Flowing Out

(Load Forecast Pg 29)

APPENDIX C: SUPPLY-SIDE SCREENING

The following sets of estimated Levelized Busbar Cost[8] charts provide an economic comparison of the technologies in their respective categories. Despite the usefulness of levelized busbar cost comparisons, comparisons involving some renewable resources, particularly wind and solar resources, can be somewhat misleading because these resources do not contribute their full installed capacity at the time of the system peak[9]. Since busbar charts attempt to levelize and compare costs on an installed kW basis, wind and solar resources appear to be more economical than they would be if the comparison was performed on a peak kW basis. The Renewables Busbar Chart shows a single point for each type of resource at the particular capacity factor specified.

<u>Base load</u>

The following technologies are found on the base load technologies screening chart:

1) 2 x 1,117 MW Nuclear
2) 825 MW Supercritical Coal with Carbon Capture and Sequestration at 60%
3) 618 MW IGCC with Carbon Capture and Sequestration at 55%
4) 700 MW – 2x2x1 Combined Cycle (Inlet Chiller and Duct Fired)

[8] While these estimated levelized busbar costs provide a reasonable basis for initial screening of technologies, simple busbar cost information has limitations. In isolation, busbar cost information has limited applicability in decision-making because it is highly dependent on the circumstances being considered. A complete analysis of feasible technologies must include consideration of the interdependence of the technologies within the context of Duke Energy Carolinas' existing generation portfolio.

[9] For purposes of this IRP, wind resources are assumed to contribute 15% of installed capacity at the time of peak and solar resources are assumed to contribute 40% of installed capacity at the time of peak.

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Baseload Technologies Screening 2012-2032

[redacted]

618 MW w/ CCS 800#/nMWHR IGCC
Combined Cycle 7FA - 2x2x1 Inlet Chiller + Duct Fired
2 x 1117 MW Nuclear (AP1000)
825 MW w/CCS 1000#/nMWHR SCPC

With lower gas prices combined with larger capacities and increased high efficiency, combined cycle is the lowest cost base load technology. However, if these curves incorporated the impacts of CO_2 escalating at a rate higher than inflation after 2032, as anticipated, the nuclear and CC costs are competitive at 90% capacity factor and above.

It is important to note that the capital and operating costs for carbon capture technology are still the subjects of ongoing industry studies and research, along with the feasibility and costs of geological sequestration of CO_2 once it is captured. The sequestration geology is not favorable in the Carolinas.

Intermediate and Peaking

The following technologies are found on the peak/intermediate technologies screening chart:

1) 800 MW Simple-Cycle 4-7FA CTs
2) 627 MW Simple- Cycle 8-7EA CTs

Peak / Intermediate Technologies Screening 2012-2032

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[redacted]

Simple Cycle (4 CTs) 7FA

Simple Cycle (8 CTs) 7EAs

The peak and intermediate screening curves include two options for simple cycle CTs with the 7FA unit making up the lower envelope of the curves. Historically, CTs are limited to peaking generation due to permit restrictions. CCs were shown as a base load technology, however with higher gas prices or not including the impacts of CO_2, CC becomes an intermediate technology.

Renewables

The following technologies are found on the renewable technologies screening chart:

1) 150 MW Wind
2) 25 MW Solar Photovoltaic
3) 5 MW Landfill Gas

Renewable Technologies Screening 2012-2032

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[redacted]

Wind Solar Photovoltaic Landfill Gas

One must remember that busbar chart comparisons involving some renewable resources, particularly wind and solar resources can be somewhat misleading because these resources do not contribute their installed capacity at the time of the system peak[10]. Since busbar charts attempt to levelize and compare costs on an installed kW basis, wind and solar resources appear to be more economic than they would be if the comparison was performed on a peak kW basis. In addition, the cost of solar does not incorporate the impact of federal and state investment tax credits or the impacts of solar technology cost decreasing over time, as was used in the IRP.

Since these renewable technologies either have no CO_2 emissions or are deemed to be carbon neutral, the cost of CO_2 emissions does not impact their operating cost. Landfill gas appears to be the least-cost renewable alternative through its entire capacity factor range with Solar Photovoltaic as the most expensive resource within the renewable category.

[10] For purposes of this IRP, wind resources are assumed to contribute 15% of installed capacity at the time of peak and solar resources are assumed to contribute 40% of installed capacity at the time of peak.

APPENDIX D: DEMAND SIDE MANAGEMENT ACTIVATION HISTORY

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
07/11-05/12	Air Conditioners	Economic Event	115 MW	101 MW	07/11/2011
		Economic Event	123 MW	102 MW	07/13/2011
		Economic Event	120 MW	108 MW	07/20/2011
		Economic Event	127 MW	115 MW	07/21/2011
		Economic Event	120 MW	110 MW	07/29/2011
		Economic Event	119 MW	115 MW	08/02/2011
		Test Emergency Event	180 MW	183 MW	08/25/2011
	Standby Generator[1]	Emergency Event	48 MW	45 MW	07/12/2011
	Interruptible Service	Emergency Event	128 MW	133 MW	07/12/2011
		Communication Test	N/A	N/A	05/08/2012
	PowerShare® Generator[1]	Emergency Event	13 MW	13 MW	07/12/2011
	PowerShare® Mandatory	Emergency Event	337 MW	339 MW	07/12/2011
	PowerShare® Voluntary	Economic Event	N/A	2 MW	07/20/2011
		Economic Event	N/A	2 MW	07/21/2011
		Economic Event	N/A	4 MW	07/22/2011
		Economic Event	N/A	2 MW	08/03/2011
09/10-06/11	Air Conditioners	Economic Event	113 MW	101 MW	06/21/2011
	Standby Generator	Emergency Event	48 MW	55 MW**	06/01/2011
	Interruptible Service	Emergency Event	148 MW	156 MW**	06/01/2011
		Communication Test	N/A	N/A	05/12/2011
	PowerShare® Generator	Emergency Event	13 MW	17 MW**	06/01/2011
	PowerShare® Mandatory	Emergency Event	335 MW	334 MW**	06/01/2011
	PowerShare® Voluntary	Economic Event	N/A	14 MW	12/15/2010
		Economic Event	N/A	2 MW**	06/01/2011
		Economic Event	N/A	16 MW	06/02/2011
	PowerShare® CallOption	Economic Event	0.2 MW	0.2 MW	12/14/2010
		Economic Event	0.2 MW	0.2 MW	12/15/2010
		Economic Event	0.2 MW	0.2 MW	01/13/2011

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
9/09 – 9/10*	Air Conditioners	Economic Event	46 MW	50 MW	6/14/2010
		Economic Event	50 MW	45 MW	6/15/2010
		Economic Event	103 MW	102 MW	6/23/2010
		Economic Event	90 MW	81 MW	07/07/2010
		Economic Event	90 MW	87 MW	07/08/2010
		Economic Event	99 MW	103 MW	07/22/2010
		Economic Event	114 MW	114 MW	07/23/2010
		Economic Event	107 MW	107 MW	08/05/2010
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	6/8/2010
	PowerShare® Voluntary	Economic Event	N/A	13 MW	6/15/2010
		Economic Event	N/A	17 MW	6/23/2010
		Economic Event	N/A	9 MW	7/7/2010
		Economic Event	N/A	7 MW	7/8/2010
		Economic Event	N/A	7 MW	7/23/2010
		Economic Event	N/A	28 MW	7/29/2010
		Economic Event	N/A	5 MW	8/4/2010
		Economic Event	N/A	7 MW	8/5/2010
	PowerShare®CallOption	Economic Event	0.2 MW	0.2 MW	07/07/2010
		Economic Event	0.2 MW	0.2 MW	07/08/2010
		Economic Event	0.2 MW	0.2 MW	08/05/2010
9/08 -9/09	Air Conditioners	Cycling Event		30 MW	8/10/2009
		SOC Full Shed Test	N/A	N/A	8/11/2009
	Water Heaters				
	Standby Generators				
	Interruptible Service	Communication Test	N/A	N/A	5/6/2009
9/07 – 9/08	Air Conditioners				
	Water Heaters				
	Standby Generators				
	Interruptible Service	Communication Test	N/A	N/A	5/6/2008
8/06 – 8/07	Air Conditioners	Cycling Test	N/A	N/A	8/30/2007
		Load Test (PLC only)	N/A	N/A	8/7/2007
		Load Test	120 MW	88 MW	8/2/2007
	Water Heaters	Cycling Test	N/A	N/A	8/30/2007
		Load Test (PLC only)	N/A	N/A	8/7/2007
		Load Test	2 MW	Included in Air Conditioners.	8/2/2007
	Standby Generators	Capacity Need	82 MW	88 MW	8/10/2007
		Capacity Need	82 MW	90 MW	8/9/2007
		Capacity Need	82 MW	79 MW	8/8/2007
		Capacity Need	82 MW	85 MW	8/1/2006
		Monthly Test			

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
8/06 – 8/07 cont.	Interruptible Service	Capacity Need	306 MW	301 MW	8/10/2007
		Capacity Need	306 MW	323 MW	8/9/2007
		Capacity Need	341 MW	391 MW	8/1/2006
		Communication Test	N/A	N/A	4/24/2007
8/05 – 7/06	Air Conditioners	Load Test	110 MW	107 MW	6/21/2006
		Cycling Test	N/A	N/A	9/21/2005
		Cycling Test	N/A	N/A	9/20/2005
	Water Heaters	Load Test	2 MW	Included in Air Conditioners.	6/21/2006
		Cycling Test	N/A	N/A	9/21/2005
		Cycling Test	N/A	N/A	9/20/2005
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	4/25/2006
8/04 – 7/05	Air Conditioners	Load Test	140 MW	148 MW	7/21/2005
		Cycling Test	N/A	N/A	8/19/2004
		Cycling Test	N/A	N/A	8/18/2004
	Water Heaters	Load Test	2 MW	Included in Air Conditioners.	7/21/2005
		Cycling Test	N/A	N/A	8/19/2004
		Cycling Test	N/A	N/A	8/18/2004
	Standby Generators	Monthly Test			
8/03 – 7/04	Air Conditioners	Load Test	110 MW	170 MW	7/14/2004
		Cycling Test	N/A	N/A	8/20/2003
	Water Heaters	Cycling Test	N/A	N/A	8/20/2003
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	4/28/2004
8/02 – 7/03	Air Conditioners	Load Test	120 MW	195 MW	7/16/2003
		Cycling Test	N/A	N/A	6/18/2003
		Cycling Test	N/A	N/A	9/18/2002
		Load Test	82 MW	122 MW	8/21/2002
	Water Heaters	Load Test	5 MW	Included in Air Conditioners.	7/16/2003
		Cycling Test	N/A	N/A	6/18/2003
		Cycling Test	N/A	N/A	9/18/2002
		Load Test	6 MW	Included in Air Conditioners.	8/21/2002
	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/7/2003
		Communication Test	N/A	N/A	11/19/2002

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
8/01 – 7/02	Air Conditioners	Cycling Test	N/A	N/A	7/17/2002
		Cycling Test	N/A	N/A	6/19/2002
		Cycling Test	N/A	N/A	8/31/2001
		Load Test	150 MW	151 MW	8/17/2001
	Water Heaters	Cycling Test	N/A	N/A	7/17/2002
		Cycling Test	N/A	N/A	6/19/2002
		Cycling Test	N/A	N/A	8/31/2001
		Load Test	6 MW	Included in Air Conditioners.	8/17/2001
	Standby Generators	Capacity Need	80 MW	20 MW Estimation due to communication problems.	6/13/2002
	Interruptible Service	Capacity Need	403 MW	370 MW	6/13/2002
		Communication Test	N/A	N/A	4/17/2002
8/00 – 7/01	Air Conditioners	Communication Test	N/A	N/A	9/14/2000
	Water Heaters	Communication Test	N/A	N/A	9/14/2000
	Standby Generators	Capacity Need	70 MW	70 MW	8/7/2000
	Interruptible Service	Communication Test	N/A	N/A	5/8/2001
7/99 – 8/00	Air Conditioners	Load Test	170-200 MW	175-200 MW	6/15/2000
	Water Heaters	Load Test	6 MW	Included in Air Conditioners.	6/15/2000
	Standby Generators	Capacity Need	70 MW	70 MW	7/2/2000
		Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/17/2000
		Communication Test	N/A	N/A	10/20/1999
9/98 – 7/99	Standby Generators	Monthly Test			
	Interruptible Service	Communication Test	N/A	N/A	5/11/1999
		Communication Test	N/A	N/A	10/27/1998
9/97 – 9/98	Air Conditioners	Load Test	180 MW	170 MW	8/18/1998
	Water Heaters	Load Test	7 MW	7 MW	8/18/1998
		Communication Test	N/A	N/A	5/29/1998
	Standby Generators	Capacity Need	68 MW	58 MW	8/31/1998
		Capacity Need	68 MW	58 MW	6/12/1998
		Monthly Test			
	Interruptible Service	Capacity Need	570 MW	500 MW	8/31/1998
		Communication Test	N/A	N/A	5/29/1998

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved	Activation Date
9/96 – 9/97	Air Conditioners	Communication Test	N/A	N/A	6/17/1997
	Standby Generators	Capacity Need	62 MW	50 MW	7/28/1997
		Capacity Need	62 MW	50 MW	7/15/1997
		Capacity Need	62 MW	50 MW	7/14/1997
		Capacity Need	62 MW	50 MW	12/20/1996
		Monthly Test			
	Interruptible Service	Capacity Need	650 MW	550 MW	7/28/1997
		Communication Tests	N/A	N/A	6/17/1997
		Communication Tests	N/A	N/A	10/16/1996

* Starting in 2010, a new category of event called an Economic Event has been added to the table.
**Corrected numbers from previous table filed.
[1]PowerShare® Generator and Standby Generator have monthly test event activations.

APPENDIX E: PROPOSED GENERATING UNITS AT LOCATIONS NOT KNOWN

A list of proposed generating units at locations not known with capacity, plant type, and date of operation included to the extent known:

Line 12 of the LCR Table for Duke Energy Carolinas identifies cumulative future resource additions needed to meet customer load reliably. Resource additions may be a combination of short/long-term capacity purchases from the wholesale market, capacity purchase options, and building or contracting of new generation

APPENDIX F: TRANSMISSION LINES AND OTHER ASSOCIATED FACILITIES PLANNED OR UNDER CONSTRUCTION

NCUC Rule R8-62(p) requires the following information:

1. For existing lines, the information required on FERC Form 1, pages 422, 423, 424 and 425: (Please see Appendix J for Duke Energy Carolinas' current FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 423.3, 424, 425, and 450.1.)

2. For lines under construction:

Transmission lines and facilities currently planned or under construction are listed below:

- Caesar 230 kV line reconductoring project - The project is needed to accommodate a transmission service request to transfer power into Progress Energy Carolinas West area. The project consists of reconductoring a 22 mile line of existing 954 ACSR conductor with 1158 ACSS conductor. The line runs between Duke's Pisgah Tie and Shiloh Switching Station. The planned in-service date for this project is June 2013.

- Antioch Tie 500/230 kV transformer upgrade project- This project is one of the FERC approved merger mitigation transmission projects. This project will replace two existing transformers, with a total capacity of 1500 MVA, with two new transformers with a total capacity of 3000 MVA. The estimated completion date for this project is June 2015.

3. For all other proposed lines, as the information becomes available:

There are no proposed lines at this time. Information will be added as it becomes available.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	Antioch Tie	Appalachian Power	525.00	525.00	Tower	27.67		1
2	Cliffside Steam Sta #6	McGuire SW	525.00	525.00	Tower	48.98		1
3	Cliffside Stm	Cliffside SW	525.00	525.00	Tower & Pole	1.14		1
4	Jocassee Tie	Bad Creek HYD	525.00	525.00	Tower	9.25		1
5	Jocassee Tie	Cliffside Tie	525.00	525.00	Tower	71.01		1
6	McGuire SW	Antioch Tie	525.00	525.00	Tower	54.40		1
7	MCGuire SW	Woodleaf Switching	525.00	525.00	Tower	29.95		1
8	Newport Tie	Progress Energy Rockingham	525.00	525.00	Tower	48.66		1
9	Newport Tie	McGuire Switching	525.00	525.00	Tower & Pole	32.24		1
10	Oconee Nuclear	Newport Tie	525.00	525.00	Tower	108.12		1
11	Oconee Nuclear	South Hall	525.00	525.00	Tower & Pole	22.50		1
12	Oconee Nuclear	Jocassee Tie	525.00	525.00	Tower	20.90		1
13	Pleasant Garden Tie	Parkwood Tie	525.00	525.00	Tower	49.65		1
14	Woodleaf Switching	Pleasant Garden Tie	525.00	525.00	Tower	53.07		1
15								
16	TOTAL 525 KV LINES					577.54		14
17								
18	Allen Steam	Catawba Nuclear	230.00	230.00	Tower	10.86		2
19	Allen Steam	Riverbend Steam	230.00	230.00	Tower	12.49		2
20	Allen Steam	Winecoff Tie	230.00	230.00	Tower	32.22		2
21	Allen Steam	Woodlawn Tie	230.00	230.00	Tower & Pole	8.44		2
22	Anderson Tie	Hodges Tie	230.00	230.00	Tower	25.79		2
23	Antioch Tie	Wilkes Tie	230.00	230.00	Tower	4.30		2
24	Beckerdite Tie	Belews Creek Steam	230.00	230.00	Tower	24.60		2
25	Beckerdite Tie	Pleasant Garden Tie	230.00	230.00	Tower	28.48		2
26	Belews Creek Steam	Ernest Switching Station	230.00	230.00	Tower	13.71		2
27	Belews Creek Steam	North Greensboro Tie	230.00	230.00	Tower	21.65		2
28	Belews Creek Steam	Pleasant Garden Tie	230.00	230.00	Tower & Pole	38.74		2
29	Belews Creek Steam	Rural Hall Tie	230.00	230.00	Tower	18.32		2
30	Bobwhite Switching	North Greensboro Tie	230.00	230.00	Tower	3.63		2
31	Buck Tie	Beckerdite Tie	230.00	230.00	Tower	23.63		2
32	Catawba Nuclear	Newport Tie	230.00	230.00	Tower & Pole	10.36		4
33	Catawba Nuclear	Pacolet Tie	230.00	230.00	Tower	41.26		2
34	Catawba Nuclear	Peacock Tie	230.00	230.00	Tower	14.85		2
35	Catawba Nuclear	Ripp Switching Station	230.00	230.00	Tower	24.44		2
36					TOTAL	8,299.09		171

Name of Respondent Duke Energy Carolinas, LLC	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2515								1
2515								2
2515								3
2515								4
2515								5
2515								6
2515								7
2515								8
2515								9
2515								10
2515								11
2515								12
2515								13
2515								14
	20,646,377	106,916,895	127,563,272					15
	20,646,377	106,916,895	127,563,272					16
								17
1272								18
1272								19
954 & 1272								20
2156								21
954								22
954								23
2156								24
954								25
1272								26
2156								27
2156								28
2156								29
2156								30
954								31
1272								32
954								33
1272								34
1272								35
	164,522,488	1,267,160,474	1,431,682,962	5,025,261	13,395,581		18,420,842	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Central Tie	Anderson Tie	230.00	230.00	Tower	23.12		2
2	Cliffside Steam	Pacolet Tie	230.00	230.00	Tower	23.01		2
3	Cliffside Steam	Shelby Tie	230.00	230.00	Tower	14.08		2
4	Cowans Ford Hydro	McGuire Switching	230.00	230.00	Tower	1.68		2
5	East Durham Tie	Parkwood Tie	230.00	230.00	Tower	19.25		2
6	Eno Tap Bent	Progress Energy (Roxboro)	230.00	230.00	Tower	13.74		2
7	Eno Tap Bent	East Durham Tie	230.00	230.00	Tower	15.78		2
8	Ernest Switching Station	Sadler Tie	230.00	230.00	Tower	12.61		2
9	Harrisburg Tie	Oakboro Tie	230.00	230.00	Tower	21.52		2
10	Hartwell Hydro	Anderson Tie	230.00	230.00	Tower	11.13		2
11	Jocassee Switching	Shiloh Switching	230.00	230.00	Tower	22.52		2
12	Jocassee Switching	Tuckasegee Tie	230.00	230.00	Tower	26.62		2
13	Lakewood Tie	Riverbend Steam	230.00	230.00	Tower	10.64		2
14	Lincoln CT	Longview Tie	230.00	230.00	Tower	30.95		2
15	Longview Tie	McDowell Tie	230.00	230.00	Tower	31.93		2
16	Marshall Steam	Beckerdite Tie	230.00	230.00	Tower	52.61		2
17	Marshall Steam	Longview Tie	230.00	230.00	Tower	29.04		2
18	Marshall Steam	McGuire Switching	230.00	230.00	Tower	13.76		2
19	Marshall Steam	Stamey Tie	230.00	230.00	Tower	13.44		2
20	Marshall Steam	Winecoff Tie	230.00	230.00	Tower	24.35		2
21	McGuire Switching	Harrisburg Tie	230.00	230.00	Tower	36.29		4
22	Mitchell River Tie	Antioch Tie	230.00	230.00	Tower & Pole	16.90		2
23	Mitchell River Tie	Rural Hall Tie	230.00	230.00	Tower	26.85		2
24	Morningstar Tie	Oakboro Tie	230.00	230.00	Tower	32.55		1
25	North Greenville Tie	Central Tie	230.00	230.00	Tower & Pole	26.22		2
26	North Greenville Tie	Shiloh Switching	230.00	230.00	Tower	8.96		2
27	Newport Tie	Morningstar Tie	230.00	230.00	Tower & Pole	33.59		1
28	Newport Tie	SCE&G (Parr)	230.00	230.00	Tower	45.38		1
29	Oakboro Tie	Progress Energy Rockingham	230.00	230.00	Tower	5.13		1
30	Oconee Nuclear	Central Tie	230.00	230.00	Tower	17.62		4
31	Oconee Nuclear	Jocassee Switching	230.00	230.00	Tower & Pole	12.28		2
32	Oconee Nuclear	North Greenville Tie	230.00	230.00	Tower & Pole	29.25		2
33	Pacolet Tie	Tiger Tie	230.00	230.00	Tower	27.96		2
34	Peach Valley Tie	Tiger Tie	230.00	230.00	Tower	15.69		2
35	Pisgah Tie	Progress Energy Skyland Stm	230.00	230.00	Tower	14.41		2
36					TOTAL	8,299.09		171

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954								1
954								2
954								3
795								4
1272								5
1272								6
1272								7
1272								8
954								9
954								10
2156								11
1272								12
954								13
795								14
954								15
954								16
1272								17
1272								18
954								19
1272								20
1272								21
954								22
954								23
954								24
954								25
954								26
954								27
954								28
954								29
1272								30
2156								31
1272								32
954								33
795								34
954								35
	164,522,488	1,267,160,474	1,431,682,962	5,025,261	13,395,581		18,420,842	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line or structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Pleasant GardenTie	Eno Tie	230.00	230.00	Tower	42.85		2
2	Ripp Switching	Riverview Switching	230.00	230.00	Tower	9.70		2
3	Ripp Switching	Shelby Tie	230.00	230.00	Tower	9.95		2
4	Riverbend Steam	Lincoln CT	230.00	230.00	Tower & Pole	11.56		2
5	Riverbend Steam	McGuire Switching	230.00	230.00	Tower	5.61		2
6	Riverbend Steam	Ripp Switching	230.00	230.00	Tower	30.12		2
7	Riverview Switching	Peach Valley Tie	230.00	230.00	Tower	19.33		2
8	SCE&G (Parr)	Bush River Tie	230.00	230.00	Tower	17.76		1
9	Shady Grove Tap	Shady Grove Tie	230.00	230.00	Tower	7.80		2
10	Shiloh Switching	Pisgah Tie	230.00	230.00	Tower	21.88		2
11	Shiloh Switching	Tiger Tie	230.00	230.00	Tower	21.46		2
12	Stamey Tie	Mitchell River Tie	230.00	230.00	Tower	35.92		2
13	Tiger Tie	North Greenville Tie	230.00	230.00	Tower	18.38		2
14	Winecoff Tie	Buck Tie	230.00	230.00	Tower	24.05		2
15								
16	TOTAL 230 KV LINES					1,395.18		135
17								
18	Nantahala Hydro	Webster Tie	161.00	161.00	Tower & Pole	25.79		3
19	Nantahala Tie	Marble Tie	161.00	161.00	Tower	16.85		2
20	Nantahala Hydro	Santeetlah	161.00	161.00	Tower	18.84		2
21	Tuckaseegee Tie	Webster	161.00	161.00	Tower & Pole	10.39		2
22	Tuckasegee Tie	Thorpe Hydro	161.00	161.00	Tower & Pole	3.16		1
23	Wesbter Tie	Lake Emory Tie	161.00	161.00	Tower & Pole	12.74		1
24	West Mill Tie	Lake Emory S. S.	161.00	161.00	Tower & Pole	6.65		1
25								
26	TOTAL 161 KV LINES					94.42		12
27								
28	Dan River Steam	Appalachian Power	138.00	138.00	Tower & Pole	6.53		1
29	115 KV Lines		115.00	115.00	Tower & Pole	55.09		5
30	100 KV Lines		100.00	100.00	Tower	1,889.35		
31	100 KV Lines		100.00	100.00	Pole	543.47		
32	100 KV Lines		100.00	100.00	Underground	1.91		
33								
34	TOTAL 100 - 138 KV LINES					1,596.35		6
35								
36					TOTAL	4,299.09		171

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954								1
795								2
954								3
795								4
1272								5
795								6
795								7
954								8
2515								9
954								10
1272								11
954								12
954								13
954								14
	41,410,192	222,729,946	264,140,138					15
	41,410,192	222,729,946	264,140,138					16
								17
795								18
795								19
795								20
795								21
397.5								22
636								23
795								24
	3,569,661	74,076,758	77,646,419					25
	3,569,661	74,076,758	77,646,419					26
								27
477								28
								29
								30
								31
								32
	69,906,534	579,670,957	649,577,491					33
	69,906,534	579,670,957	649,577,491					34
								35
	164,522,488	1,267,160,474	1,431,682,962	5,025,261	13,395,581		18,420,842	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	66 KV Lines		66.00	66.00	Pole	105.12		1
2	66 KV Lines		66.00	66.00	Tower	11.51		
3								
4	TOTAL 66 KV LINES					116.63		1
5								
6	44 KV Lines		44.00	44.00	Tower	198.58		
7	44 KV Lines		44.00	44.00	Pole	2,197.54		
8	44 KV Lines		44.00	44.00	Underground	0.35		1
9								
10	TOTAL 44 KV LINES					2,396.47		1
11								
12	33 KV Lines		33.00	33.00	Tower & Pole	16.48		
13	24 KV Lines		24.00	24.00	Tower & Pole	81.70		
14	24 KV Lines		24.00	24.00	Underground	0.48		1
15	12 KV Lines		12.00	12.00	Tower & Pole	23.60		
16	12 KV Lines		12.00	12.00	Underground	0.24		1
17								
18	TOTAL 12-33 KV LINES					122.50		2
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	8,299.09		171

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
								2
	4,465,431	25,762,173	30,227,604					3
	4,465,431	25,762,173	30,227,604					4
								5
								6
								7
								8
	23,960,076	253,509,853	277,469,929					9
	23,960,076	253,509,853	277,469,929					10
								11
								12
								13
								14
								15
								16
	564,217	4,493,892	5,058,109					17
	564,217	4,493,892	5,058,109					18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
				5,025,261	13,395,581		18,420,842	35
	164,522,488	1,267,160,474	1,431,682,962	5,025,261	13,395,581		18,420,842	36

Name of Respondent Duke Energy Carolinas, LLC	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2011/Q4

FOOTNOTE DATA

Schedule Page: 422 Line No.: 1 Column: h

For column (h) the number of circuits - 1 & 2

Schedule Page: 422 Line No.: 1 Column: i

All Conductors in column (i) are ACSR shown in MCM.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Overhead New Lines						
2	Cliffside Unit 6	Cliffside Tie	1.14		9.00	1	
3	E Durham Tie	Stallings Rd Ret	5.93		11.00	1	
4	Glen Raven Mn	Pleasant Garden	0.01	Pole	200.00	2	
5	American Express Tap 1		0.10	Pole	30.00	1	
6	American Express Tap 2		0.08	Pole	63.00	1	
7	Andale		2.14		13.00	1	
8	Pisgah T	Horseshoe T	0.05	Tower	20.00	1	
9	Cliffside Tie Service Tap		0.19	Pole	26.00	1	
10	Camp Creek Ret Tap		2.84	Pole	12.00	1	
11	Webster	Hyatt Tie	0.02	Pole	100.00	1	
12	Fagan Bent	ColumbusRet	0.02	Pole	50.00	1	
13	Belews Creek Pump Station		0.05	Pole	20.00	1	
14	O'neal Retail Tap		0.03	Pole	67.00	1	
15	Tiger Tie	Campobello Tie	0.44		12.00	1	
16							
17							
18							
19							
20							
21							
22							
23							
24	Overhead Major Rebuild						
25	Jocassee Tie	Cliffside Tie	0.07	Pole	29.00	1	
26	Cliffside Steam Unit 6	McGurie SW	0.07	Pole	72.00	1	
27	Foote Mineral Tap		0.31	Pole	10.00	1	
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		13.49		744.00	18	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
2515	ACSR		525		2,166,296	1,327,730		3,494,026	2
954	ACSR		100	65,249	5,192,796	3,182,681		8,440,726	3
795	ACSR		100		181,396	111,178		292,574	4
566.5	ACSR		100		131,591	80,652		212,243	5
556.5	ACSR		100		73,750	45,201		118,951	6
954	AAC		100	81,456	859,493	526,786		1,467,735	7
954	ACSR		100		279,956	171,586		451,542	8
336	ACSR		44		209,760	128,563		338,323	9
795	ACSR		66		1,186,087	726,956		1,913,043	10
397.5	ACSR		66		243,069	148,977		392,046	11
336.4	ACSR		44		33,612	20,601		54,213	12
556	ACSR		44		161,200	98,800		260,000	13
556	ACSR		100		114,001	69,871		183,872	14
954	ACSR		100	206,932	336,557	206,277		749,766	15
									16
									17
									18
									19
									20
									21
									22
									23
									24
2515	ACSR		525		436,083	267,277		703,360	25
2515	ACSR		525	290,475	406,961	249,428		946,864	26
336	ACSR		44		98,973	60,661		159,634	27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				644,112	12,111,581	7,423,225		20,178,918	44

GENERATION AND ASSOCIATED TRANSMISSION FACILITIES SUBJECT TO CONSTRUCTION DELAYS

A list of any generation and associated transmission facilities under construction which have delays of over six months in the previously reported in-service dates and the major causes of such delays. Upon request from the NCUC Staff, the reporting utility shall supply a statement of the economic impact of such delays:

There are no delays over six months in the stated in-service dates.

2012 FERC Form 715

The 2012 FERC Form 715 filed March 2012, is confidential and filed under seal.

APPENDIX G: OTHER INFORMATION (ECONOMIC DEVELOPMENT)

Customers Served Under Economic Development:

In the NCUC Order issued in Docket No. E-100, Sub 97, dated November 15, 2002, the NCUC ordered North Carolina utilities to review the combined effects of existing economic development rates within the approved IRP process and file the results in its short-term action plan. The incremental load (demand) for which customers are receiving credits under economic development rates and/or self-generation deferral rates (Rider EC), as well as economic redevelopment rates (Rider ER) as of June 2012 is:

Rider EC:
89 MW for North Carolina
9 MW for South Carolina

Rider ER:
3 MW for North Carolina
1 MW for South Carolina

APPENDIX H: NON-UTILITY GENERATION/CUSTOMER-OWNED GENERATION/STAND-BY GENERATION:

In the NCUC's Order *Revising Integrated Resource Planning Rules* in Docket No. E-100, Sub 111, dated July 11, 2007, the NCUC required North Carolina utilities to provide a separate list of all non-utility electric generating facilities in the North Carolina portion of their control areas, including customer-owned and standby generating facilities, to the extent possible. Duke Energy Carolinas' response to that Order was based on the best available information, and the Company has not attempted to independently validate it. In addition, some of that information duplicates data that Duke Energy Carolinas supplies elsewhere in this IRP.

The Company has continued to add small non-utility electric generation since the 2010 IRP. An updated listing is included below. The tables in this Appendix represent those non-utility generation and stand-by generation contracts that were signed as of August 1, 2012. It is prudent to note that additional contracts are in various phases of signing and negotiation, and these tables frequently change. Tables 5.E and 5.F in Chapter 5 also represent a high-level snapshot of some of the wholesale non-utility generation contracts signed as of August 1, 2012.

The Company also includes a full list in its annual status report filed in Docket No. E-100, Sub 41B.

PURPA Qualifying Facilities

PURPA QUALIFYING FACILITIES (Selling electricity to Duke Energy Carolinas)				
Supplier	**City**	**Nameplate KW**	**Primary Fuel Type**	**Part of Total Supply Resources [1]**
203 Neotrantor LLC	Hendersonville	9	Photovoltaic	Yes
Active Concepts - LLC	Lincolnton	75	Photovoltaic	Yes
Advantage Investment Group, LLC	Gastonia	640	Hydroelectric	Yes
AKS Realty & Development (Solar Tech South)	Chapel Hill	3	Photovoltaic	Yes
Alamance Hydro, LLC	Glen Raven	240	Hydroelectric	Yes
Amelia M. Collins	Chapel Hill	4	Photovoltaic	Yes
Andrews Truss, Inc.	Andrews	10	Photovoltaic	Yes
Anna L. Reilly	Winston-Salem	4	Photovoltaic	Yes
Arnold M. Schechter	Chapel Hill	10	Photovoltaic	Yes
Arrowood Construction	Franklin	4	Wind	Yes
Barbara Ann Evans	Caroleen	324	Hydroelectric	Yes
Barry L Bingham	Lawndale	10	Photovoltaic	Yes
Barry R. Wharton	Bryson City	3	Photovoltaic	Yes
Benjamin R. Eustice	Conover	4	Photovoltaic	Yes
Berjouhi Keshguerian	High Point	4	Photovoltaic	Yes
Gail S. Schneitler	Pilot Mountain	10	Photovoltaic	Yes
Biomerieux, Inc.	Durham	124	Photovoltaic	Yes
Black Hawk, Inc.	Hendersonville	9	Photovoltaic	Yes
Boyd Leon Hyder	Hendersonville	10	Photovoltaic	Yes
Brien R. Deuterman	Greensboro	4	Photovoltaic	Yes
Bryan C. Turner	Durham	7	Photovoltaic	Yes
Burlington Hydro LLC	Burlington	150	Hydroelectric	Yes
Byron Matthews	Chapel Hill	3	Photovoltaic	Yes
Catawba County - Blackburn Landfill	Newton	4,000	Landfill Gas	Yes
Catherine C. Hooks	Troutman	3	Photovoltaic	Yes
Chad D Davis	Burlington	3	Photovoltaic	Yes
Chapel Hill Tire Company	Carrboro	16	Photovoltaic	Yes
Charles Brandon Mitchell	Durham	4.16	Photovoltaic	Yes
Christopher D. Hardin	Huntersville	6	Photovoltaic	Yes
Cisco Systems Inc.	Triangle Park	100	Photovoltaic	Yes
City of Charlotte	Charlotte	250	Photovoltaic	Yes
Cliffside Mills, LLC	Cliffside	1,600	Photovoltaic	Yes
Commonwealth Brands Inc.	Reidsville	169	Photovoltaic	Yes
Concepts By Gary, LLC	Advance	10	Photovoltaic	Yes
Concord Energy LLC	Concord	11500	Landfill Gas	Yes
CPIM, LLC	Carrboro	9.9	Photovoltaic	Yes
Daniel E. Suman	Chapel Hill	4	Photovoltaic	Yes
David Birkhead	Hillsborough	2	Photovoltaic	Yes
David E. Guinnup	Durham	4	Photovoltaic	Yes
David E. Shi	Brevard	3	Photovoltaic	Yes
David H. Newman	Greensboro	6	Photovoltaic	Yes
David Boyer	Sandy Ridge	4	Photovoltaic	Yes
David M. Thomas	Lenoir	6	Photovoltaic	Yes
David A. Ringenburg	Chapel Hill	8	Photovoltaic	Yes
David W. Walters	Sylva	5	Photovoltaic	Yes
David Wiener DBA JZ Solar Electric	Chapel Hill	3	Photovoltaic	Yes
Davidson Gas Producers, LLC-Landfill Gas	Lexington	1600	Landfill Gas	Yes
DDM Mortgage Corporation	Browns Summit	72	Photovoltaic	Yes
Decision Support Management LLC	Matthews	30	Photovoltaic	Yes
Dee Industries, Inc.	China Grove	4	Photovoltaic	Yes

PURPA Qualifying Facilities cont.

Supplier	City	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources [1]
Delta Products Corporation	RTP	30	Photovoltaic	Yes
Diann M. Barbacci	Kernersville	2	Photovoltaic	Yes
Dirk J. Spruyt	Chapel Hill	4	Photovoltaic	Yes
Dixon Dairy Road	Kings Mountain	4,000	Photovoltaic	Yes
Don A Bicknell	Charlotte	4	Photovoltaic	Yes
Douglas Albright Thompson	Burlington	3	Photovoltaic	Yes
Dr. James David Branch	Winston-Salem	11	Photovoltaic	Yes
Ecologic-Studio, LLC	Chapel Hill	4	Photovoltaic	Yes
Edward W. Witkin	Chapel Hill	6	Photovoltaic	Yes
Elaine K. Scott	Charlotte	3	Photovoltaic	Yes
Elizabeth D Burns	Charlotte	4	Photovoltaic	Yes
Elizabeth D. Hilborn	Chapel Hill	3	Photovoltaic	Yes
Elizabeth J Mutran	Durham	4	Photovoltaic	Yes
Elsewhere Living Museum	Greensboro	4.8	Photovoltaic	Yes
Eric L. Gaylord	Matthews	4	Photovoltaic	Yes
Erik Kimelman	Greensboro	5	Photovoltaic	Yes
Erik P. Raudsep	Durham	4	Photovoltaic	Yes
Everett Williams	Robbinsville	5	Micro-hydro	Yes
FLS Owner II, LLC- McDowell Senior Center-Solar	Marion	4	Photovoltaic	Yes
Fogleman Construction, Inc.	Graham	3	Photovoltaic	Yes
Foothills Wineworx Inc.	Morganton	24	Photovoltaic	Yes
Frances L. Thompson	Hickory	5	Photovoltaic	Yes
Friendship Trays, Inc.	Charlotte	8	Photovoltaic	Yes
Gail D. Schmidt	Tryon	3	Photovoltaic	Yes
Gail Severs Schneitler	Pilot Mountain	10	Photovoltaic	Yes
Gas Recovery Systems, LLC	Concord	5,000	Landfill Gas	Yes
Gaston County	Dallas	4,800	Landfill Gas	Yes
Geoffrey E. Gledhill	Cedar Grove	6	Photovoltaic	Yes
George F. Fralick	Edneyville	3	Photovoltaic	Yes
Gerald W. Meisner & Harol M. Hoffman	Greensboro	4	Photovoltaic	Yes
Gerry Priebe	Bryson City	7	Photovoltaic	Yes
Greensboro Plumbing Supply	Greensboro	50	Photovoltaic	Yes
Gwenyth T. Reid	Hillsborough	4	Photovoltaic	Yes
H. Malcolm Hardy	Chapel Hill	3	Photovoltaic	Yes
Haneline Power, LLC	Millersville	365	Hydroelectric	Yes
Hardins Resources Company	Hardens	820	Hydroelectric	Yes
Haw River Hydro Company	Saxapahaw	1,500	Hydroelectric	Yes
Hayden-Harman Foundation	Burlington	2	Photovoltaic	Yes
Hendrik J. Roddenburg	Chapel Hill	3	Photovoltaic	Yes
Holzworth Holdings, Inc.	Durham	3	Photovoltaic	Yes
Innovative Solar Solutions	Charlotte	4	Photovoltaic	Yes
Irvine River Company	Eden	500	Hydroelectric	Yes
J Chester Grey	Vale	10	Photovoltaic	Yes
Jafasa Farms - Residence	Horseshoe	6	Photovoltaic	Yes
Jafasa Farms - Greenhouse	Horseshoe	6	Photovoltaic	Yes
James B. Sherman	Chapel Hill	5	Photovoltaic	Yes
James E. Jackson	Mount Airy	12.26	Photovoltaic	Yes
James Edward Rowell Jr.	Charlotte	4	Photovoltaic	Yes
James J. Boyle	Durham	4	Photovoltaic	Yes
James Lee Johnson	Matthews	2	Photovoltaic	Yes

PURPA Qualifying Facilities cont.

Supplier	City	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources [1]
James Richard Trevathan	Highlands	3	Photovoltaic	Yes
JDC Manufacturing, LLC	Reidsville	90	Photovoltaic	Yes
Jeffery L. Pardue	Wilkesboro	4	Photovoltaic	Yes
Jerome Levit	Graham	2	Photovoltaic	Yes
Jim and Linda Alexander	Chapel Hill	4	Photovoltaic	Yes
Joel L. Hager	Salisbury	4	Photovoltaic	Yes
John B. Robbins	Concord	10	Photovoltaic	Yes
John D. Whitler	Randleman	4	Photovoltaic	Yes
John H. DiLiberti	Hillsborough	10	Photovoltaic	Yes
John J. Hammiller	Jonesville	4	Photovoltaic	Yes
Juba Aluminum Products Company, Inc.	Concord	9	Photovoltaic	Yes
Katharine L. Popejoy	Charlotte	5	Photovoltaic	Yes
Keith Adam Smith	Nebo	2	Photovoltaic	Yes
Kenneth A. Bollen	Chapel Hill	2	Photovoltaic	Yes
Kevin Newell	Mooresville	4	Photovoltaic	Yes
KMBA, LLC	Charlotte	9	Photovoltaic	Yes
Laura J. Ballance	Durham	7	Photovoltaic	Yes
Lawrence Electric, Inc.	Salisbury	2	Photovoltaic	Yes
Lawrence Lee Adrian	Durham	4	Photovoltaic	Yes
Leon's Beauty School, Inc.	Greensboro	35	Photovoltaic	Yes
Lynwood Solar I, LLC	Kings Mountain	135	Photovoltaic	Yes
Marilyn M. Norfolk	Chapel Hill	5	Photovoltaic	Yes
Mark A. Powers	Chapel Hill	2	Photovoltaic	Yes
Mark S. Trustin Attorney At Law	Durham	3	Photovoltaic	Yes
Markus Andres	Chapel Hill	4	Photovoltaic	Yes
Martin Joseph Lashua	Huntersville	4	Photovoltaic	Yes
Martin Truex Jr. LLC	Mooresville	60	Photovoltaic	Yes
Mary Karen Nicholson	Mebane	2	Photovoltaic	Yes
Matthew T. Ewers	Charlotte	3	Photovoltaic	Yes
Mayberry Solar LLC	Mount Airy	1,000	Photovoltaic	Yes
Mayo Hydropower, LLC	Mayodan	951	Hydroelectric	Yes
Mayo Hydropower, LLC	Mayodan	1,275	Hydroelectric	Yes
Megawatt Solar, Inc.	Hillsborough	5	Photovoltaic	Yes
Mehul Shah	Huntersville	4	Photovoltaic	Yes
Michael G. Hitchcock	Yadkinville	8	Photovoltaic	Yes
Michael J. Peterson	Charlotte	1.89	Photovoltaic	Yes
Mill Shoals Hydro Company, Inc.	High Shoals	1,800	Hydroelectric	Yes
Molly S. Payne	Pinnacle	4	Photovoltaic	Yes
MP Durham, LLC	Durham	3,180	Landfill Gas	Yes
Namron, Inc.	Charlotte	4	Photovoltaic	Yes
Nathaniel J. Poovey	Newton	5	Photovoltaic	Yes
National Renewable Energy Corporation	Gastonia	635	Photovoltaic	Yes
Newton-Conover City Schools	Conover	135	Photovoltaic	Yes
Norris Job Galyan	Concord	4	Photovoltaic	Yes
Northbrook Carolina Hydro, L.L.C. - Turner Shoals	Mill Spring	5,500	Hydroelectric	Yes
Nypro INC dba Nypro Carolinas	Mebane	222	Photovoltaic	Yes
Oakdale Holding, LLC	Hillsborough	18	Photovoltaic	Yes
Oenophilia	Hillsborough	18	Photovoltaic	Yes
Old Dominion Freight Line Inc	Thomasville	1,500		Yes
Optima Engineering	Charlotte	8	Photovoltaic	Yes

PURPA Qualifying Facilities cont.

Supplier	City	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources [1]
Pacifica Master Homeowners' Association	Carrboro	5	Photovoltaic	Yes
Paul C. Kuo	Chapel Hill	3	Photovoltaic	Yes
Paul G. Keller DBA Futility	Chapel Hill	4	Photovoltaic	Yes
Paul M. Neubauer	Graham	2	Photovoltaic	Yes
Philip E. Miner	Ellenboro	5	Photovoltaic	Yes
Phillip B. Caldwell	Brevard	3	Photovoltaic	Yes
Pierre Burke	Sylva	9	Photovoltaic	Yes
Pickens Mill Hydro, LLC	Charlotte	600	Hydroelectric	Yes
Pippin Home Designs	Sherrils Ford	4	Photovoltaic	Yes
Public Library of Charlotte & Meck. County	Charlotte	33	Photovoltaic	Yes
R. Lawrence Ashe, Jr.	Glenville	4	Photovoltaic	Yes
Rainer Dammers	Chapel Hill	4	Photovoltaic	Yes
Rajah Y. Chacko	Charlotte	3	Photovoltaic	Yes
Rajendra Morey	Durham	7	Photovoltaic	Yes
Ramona L. Sherwood	Charlotte	4	Photovoltaic	Yes
RayLen Vineyards, Inc.	Mocksville	10	Photovoltaic	Yes
Rebecca A. Durante	Charlotte	2	Photovoltaic	Yes
Rebecca G. Laskody	Chapel Hill	3	Photovoltaic	Yes
Rebecca T. Cobey	Chapel Hill	2	Photovoltaic	Yes
Richard J. Harkrader	Durham	4	Photovoltaic	Yes
Richard Sweeney	Belmont	4	Photovoltaic	Yes
Robert Carton	Glenville	9.9	Photovoltaic	Yes
Robert E Adams	Hendersonville	4	Photovoltaic	Yes
Robert Skirboll	Greensboro	4	Photovoltaic	Yes
Robert W. Stone	Charlotte	5	Photovoltaic	Yes
Ron B. Rozzelle	Graham	6	Photovoltaic	Yes
Ron O. Bryant	Norwood	5.16	Photovoltaic	Yes
Ronald Lippard	Randleman	4	Photovoltaic	Yes
Ronald R. Butters	Durham	5	Photovoltaic	Yes
Ronnie B Power (Sharpe-Falls)	Warrensville	200	Hydroelectric	Yes
Runaway Properties, LLC	Hendersonville	9	Photovoltaic	Yes
Russell Von Stein	Brevard	3	Photovoltaic	Yes
Salem Energy Systems, L.L.C.	Winston-Salem	4,750	Landfill Gas	Yes
Samuel C. Bingham	Rutherfordton	4	Photovoltaic	Yes
J. Chester Grey	Vale	10	Photovoltaic	Yes
SanDan Farm	McLeansville	24	Photovoltaic	Yes
Scot Friedman	Greensboro	5	Photovoltaic	Yes
Shawn L. Slome	Chapel Hill	2	Photovoltaic	Yes
Sheldon R. Pinnell	Durham		Photovoltaic	Yes
Shoe Show, Inc.	Concord	4500	Photovoltaic	Yes
South Yadkin Power, Inc.	Greensboro	1,500	Hydroelectric	Yes
SouthData, Inc.	Mount Airy	9.87	Photovoltaic	Yes
Spencer Yost	Pfafftown	4	Photovoltaic	Yes
Stanley D. Chamberlain	Chapel Hill	9	Photovoltaic	Yes
Stewart Bible	Durham	2	Photovoltaic	Yes
Stephen C. Graf	Cedar Grove	5	Photovoltaic	Yes
Steven D. Holdaway	Chapel Hill	5.17	Photovoltaic	Yes
Steve Mason Enterprises Inc	Gastonia	750	Hydroelectric	Yes
Stoneville Solar, LLC	Stoneville	9	Photovoltaic	Yes
Strates Inc. DBA Westtown Eatery & Express	Winston-Salem	6	Photovoltaic	Yes

PURPA Qualifying Facilities cont.

Supplier	City	Nameplate KW	Primary Fuel Type	Part of Total Supply Resources [1]
Lamar Bailes	Walhalla	5	Photovoltaic	Yes
Lawrence B. Miller	Anderson	3	Photovoltaic	Yes
Lockhart Power Company	Wellford	1,600	Landfill Gas	Yes
Northbrook Carolina Hydro, L.L.C. - Boyd's Mill	Ware Shoals	1,500	Hydroelectric	Yes
Northbrook Carolina Hydro, L.L.C. - Hollidays Bridge	Belton	3,500	Hydroelectric	Yes
Northbrook Carolina Hydro, L.L.C. - Saluda	Greenville	2,400	Hydroelectric	Yes
Pelzer Hydro Company, Inc.	Pelzer	2,020	Hydroelectric	Yes
Pelzer Hydro Company, Inc.	Pelzer	3,300	Hydroelectric	Yes
Thomas W. Bates	Simpsonville	5	Photovoltaic	Yes

Stand-by Generator Customers

County	State	Nameplate kW
Alamance	NC	875
Alamance	NC	550
Alamance	NC	600
Alamance	NC	200
Alamance	NC	800
Alamance	NC	1150
Burke	NC	200
Burke	NC	600
Cabarrus	NC	2950
Cabarrus	NC	680
Catawba	NC	1500
Catawba	NC	1750
Catawba	NC	1040
Catawba	NC	500
Catawba	NC	500
Cleveland	NC	4480
Davidson	NC	300
Davidson	NC	750
Davidson	NC	2950
Durham	NC	1600
Durham	NC	1300
Durham	NC	3000
Durham	NC	2250
Durham	NC	1000
Durham	NC	350
Durham	NC	1825
Elkin	NC	400
Forsyth	NC	800
Forsyth	NC	1800
Forsyth	NC	400
Forsyth	NC	750
Forsyth	NC	1050
Forsyth	NC	3000
Forsyth	NC	500
Forsyth	NC	2000
Forsyth	NC	3750
Forsyth	NC	3000

Stand-by Generator Customers cont.

County	State	Nameplate kW
Gaston	NC	265
Gaston	NC	350
Gaston	NC	500
Gaston	NC	350
Gaston	NC	440
Gaston	NC	1590
Gaston	NC	210
Granville	NC	1250
Granville	NC	750
Guilford	NC	1350
Guilford	NC	125
Guilford	NC	700
Guilford	NC	2500
Guilford	NC	1280
Guilford	NC	750
Guilford	NC	250
Henderson	NC	1000
Henderson	NC	500
Henderson	NC	1000
Iredell	NC	750
McDowell	NC	650
Mecklenburg	NC	1750
Mecklenburg	NC	1250
Mecklenburg	NC	200
Mecklenburg	NC	2250
Mecklenburg	NC	1200
Mecklenburg	NC	420
Mecklenburg	NC	400
Mecklenburg	NC	2200
Mecklenburg	NC	1450
Mecklenburg	NC	1450
Mecklenburg	NC	3200
Mecklenburg	NC	10000
Orange	NC	500
Orange	NC	1135
Orange	NC	500
Orange	NC	2000

Stand-by Generator Customers cont.

County	State	Nameplate kW
Rockingham	NC	1700
Rockingham	NC	750
Rowan	NC	1500
Surry	NC	600
Surry	NC	750
Surry	NC	500
Union	NC	400
Wilkes	NC	600
Wilkes	NC	750
Wilkes	NC	750
Wilkes	NC	155
Yadkin	NC	1200
Yadkin	NC	500

PowerShare® Generator Customers

County	State	Nameplate kW
Greenwood	SC	1500
Laurens	SC	447
Lancaster	SC	1875
Spartanburg	SC	500
Spartanburg	SC	2900
Durham	NC	13400
Durham	NC	10900
Jackson	NC	12500
Guilford	NC	2000

APPENDIX I: WHOLESALE PROJECTIONS FROM EXISTING AND POTENTIAL CUSTOMERS

Table I.1 below provides the historical and projected growth in peak loads for the Company's wholesale customers. The wholesale customer growth rates vary. With respect to wholesale sales contracts, the Company has developed econometric forecasting models for the larger wholesale customer in a process similar to that used for retail to produce MWH sales forecasts. For smaller wholesale customers, however, their forecasted growth is assumed to be the same as Duke Energy Carolinas' retail growth.

It is important to note that the growth rates for Central and NCEMC Supplemental Requirements) are primarily driven by terms of the contract. The Central Sale provides for a seven year "step-in" to Central's full load requirement such that the Company will provide 15% of Central's total member cooperative load in Duke's Balancing Authority Area requirement in 2013. This initial load requirement will be followed by subsequent 15% annual increases in load over the following six years up to a total of 100% of Central's load requirements. The NCEMC Fixed Load Shape is essentially a fixed quantity of capacity and energy specified by the contract

The wholesale sales contracts, shown in Table 3.D, are gross loads and are not reduced by the resources that some wholesale entities operate.

TABLE I.1 (CONFIDENTIAL)

[redacted]

There are no undesignated wholesale contracts identified in the 2012 Duke Energy Carolinas IRP.

APPENDIX J: CARBON NEUTRALITY PLAN

Greenhouse Gas Reduction Compliance Plan – Cliffside Unit 6

On January 29, 2008, the NCDAQ issued the Air Quality Permit to Duke Energy Carolinas for the Cliffside Unit 6. The Permit specifically requires that Duke Energy Carolinas implement a Greenhouse Gas Reduction Plan (Greenhouse Plan), and specifically obligates Duke Energy Carolinas to take the following actions in recognition of NCDAQ's issuance of the Permit for Cliffside Unit 6: (1) retire 800 MWs of coal capacity in North Carolina in accordance with the schedule set forth in Table J.1, which is in addition to the retirement of Cliffside Units 1 – 4; (2) accommodate, to the extent practicable, the installation and operations of future carbon control technology; and (3) take additional actions to make Cliffside Unit 6 carbon neutral by 2018.

With regard to obligation (1) identified above, as shown in Table J.1 below, Duke Energy Carolinas proposes to retire up to 1299 MW at the following generating units to satisfy the required retirement schedule set forth in the Greenhouse Plan.

<u>Table J.1</u> - Cumulative Coal Plant Retirements

	Greenhouse Plan Retirement Schedule Capacity in MW	IRP Retirement Schedule Capacity in MW (per Table 5.D)[1]	Description for IRP Retirement Schedule
by end of 2011		113	Buck 3 & 4
by end of 2012		389	Dan River 1-3
by end of 2015	350	1299	Riverbend 4 - 7, Buck 5 & 6, Lee 1&2
by end of 2016	550	1299	Note [2]
by end of 2018	**800**	**1299**	

[1] In the 2012 IRP, this data appears in Table 5.D, page 55. Plant retirements that were applicable to the first obligation were put in this table. References have been updated to match the 2012 IRP.
[2] The IRP Retirement Schedule indicates that the retirements would exceed the Greenhouse Plan by close to 50%.

With respect to obligation (2) listed above, the requirement to build Cliffside Unit 6 to accommodate future carbon technologies has been met by allocating space at the 1100 acre site for this equipment and incorporating practical energy efficiency designs into the plant.

With respect to obligation (3) to render Cliffside Unit 6 carbon neutral by 2018, the proposed plan to achieve this requirement is set forth below. The Greenhouse Gas Reduction Plan states that the plan for carbon neutrality:

may include energy efficiency, carbon free tariffs, purchase of credits, domestic and international offsets, additional retirements or reduction in fossil fuel usage as carbon free generation becomes available, and carbon reduction through the development of smart grid, plug in hybrid electric vehicles or other carbon mitigation projects. Such actions will be included in plans to be filed with the NCUC and will be subject to NCUC approval, including appropriate cost recovery of such actions. In addition, the plans shall be submitted to the Division of Air Quality, which will evaluate the effect of the plans on carbon, and provide its conclusions to the NCUC.

Duke Energy Carolinas included the plan for carbon neutrality in the 2011 IRP in order to satisfy the requirement to file and seek approval of the plan from the NCUC as required by the NCDAQ Air Permit. The NCUC's Order Approving 2011 Annual Updates to 2010 Biennial Resource Plans and 2011 REPS Compliance Plans issued on May 30, 2012, states that "the Commission is approving the Plan itself as a reasonable path for Duke's compliance with the carbon emission reduction standards of the air quality permit and is not approving any individual specific activities nor expenditures for any activities shown in the Plan."

The estimated emissions reductions required to render Cliffside Unit 6 carbon neutral in 2018 are approximately 5.3 million tons of carbon dioxide (the Emission Reduction Requirement). The Company calculated the estimated emission reductions by estimating the actual tons of carbon dioxide emissions that will be released per year from Cliffside Unit 6 less 681,954 tons of carbon dioxide emissions that was historically generated from Cliffside Units 1 – 4 and will be eliminated by the retirement of these units. (See Table J.2 below.)

Table J.2 - Emission Reduction Requirement

Actions	**Tons of CO_2 Equivalent Emissions**	**Notes**
Cliffside Unit 6	6,000,000	Expected Annual Emissions (based on an approximate 90% capacity factor)
Less Cliffside Units 1 – 4	(681,954)	Average of emissions in 2007 & 2008[1]
Total Increase	**5,318,046**	**Emissions Reduction Requirement**

[1]The emissions attributable to coal plant retirements are identified as the highest two year average CO_2 emissions for the five years prior to the operations of Unit 6 in 2012, consistent with the methodology for calculating emissions for major modification under the Clean Air Act Prevention of Significant Deterioration regulations.

The Company's plan for meeting the Emissions Reductions Requirements includes actions from multiple categories and associated methodologies for determining the offset value known as "Qualifying Actions" (defined below and as further indicated in Table J.3).

For 2018, the Company has identified approximately 9.2 million annual tons of carbon dioxide emissions reductions and a life-time credit of 600,000 tons of carbon dioxide bio-sequestration as eligible Qualifying Actions. (See Table J.3) The Qualifying Actions include the avoidance of carbon dioxide emission releases from coal plant retirements, addition of renewable resources, implementation of energy efficiency measures, nuclear and hydropower capacity upgrades. This also includes the expected retirement of coal-fired operations at Lee Units 1, 2 and 3 in South Carolina in 2015. In addition, carbon dioxide bio-sequestration offsets from the Greentrees program, which sequesters carbon as trees grow, is identified as a Qualifying Action.

While the reductions associated with retirements for each of the coal plants shall be the same each year, the reductions for the remaining Qualifying Actions will vary based on actual results for each of the categories and the then current system carbon intensity factor. The system carbon intensity factor shall be equal to the actual carbon dioxide emissions of all Company-owned generation dedicated for Duke Energy Carolina customers divided by the megawatt hours generated by those same resources (the "Conversion Factor").

<u>Table J.3</u> - Qualifying Actions for carbon dioxide emission reductions

Categories	**Tons of CO_2 Equivalent Emissions**	**Methodology Description**
Buck 3	216,202	Average of emissions in 2007 & 2008[1]
Buck 4	139,429	Average of emissions in 2007 & 2008[1]
Buck 5	606,837	Average of emissions in 2007 & 2008[1]
Buck 6	653,860	Average of emissions in 2007 & 2008[1]
Riverbend 4	462,314	Average of emissions in 2007 & 2008[1]
Riverbend 5	435,895	Average of emissions in 2007 & 2008[1]
Riverbend 6	684,010	Average of emissions in 2007 & 2008[1]
Riverbend 7	710,023	Average of emissions in 2007 & 2008[1]
Dan River 1	249,900	Average of emissions in 2007 & 2008[1]
Dan River 2	282,944	Average of emissions in 2007 & 2008[1]
Dan River 3	677,334	Average of emissions in 2007 & 2008[1]
Lee 1 [5]	335,583	Average of emissions in 2007 & 2008[1]
Lee 2 [5]	390,965	Average of emissions in 2007 & 2008[1]
Lee 3 [5]	783,658	Average of emissions in 2007 & 2008[1]
Conservation	1,585,494	In 2018, 3,963,735 MWH “Conservation and Demand Side Management Programs”[2] is multiplied by a Conversion Factor of 0.40.
Renewable Energy	623,362	In 2018, 602 MW per the Table 8.E “MW Nameplate Capacity”.[3] Is multiplied by an assumed 30% (wind), 20% (solar), and 85% (biomass) capacity factor and a Conversion Factor of 0.40.
Bridgewater Hydro	7,997	Indicates 8.75 MW increase in capacity. This is multiplied by a 26% capacity factor and a Conversion Factor of 0.40.
Nuclear Uprates	357,829	Assumed 111 MW of nuclear uprates by June of 2018.[4] Assumed a 92% capacity factor and a Conversion Factor of 0.40.
Total Annual	9,203,636	

[1] The emissions attributable to coal plant retirements are identified as the highest two year average CO_2 emissions for the five years prior to the operations of Unit 6 in 2012, consistent with the methodology for calculating emissions for major modifications under the Clean Air Act Prevention of Significant Deterioration regulations. Company reserves the right to use any credits for reduction of nitrogen oxide, sulfur dioxide and carbon dioxide emissions generated by retirement of units retired under the plan consistent with provisions of State and federal law.
[2] Data is from Table 4.A, page 39 of the 2012 IRP.
[3] Data is from the Table 8.E on page 99 of the 2012 IRP. Actual nameplate capacity is 602 MW. The contribution to peak is 288 MW.
[4] Data is a portion of the total capacity addition on page 93 of 2012 IRP prior to June 2018.
[5] Lee Units 1, 2 and 3 are planned for retirement by April 15, 2015. Alternatively, Duke Energy is considering converting one or more of these units to natural gas to allow continued operation for peak generation demand only (at a low annual capacity factor). Any CO_2 from operating with natural gas would be subtracted from the reductions shown in the table.

As the proposed Plan methodology has been approved, Duke Energy Carolinas shall provide a compliance report in the 2019 IRP filing indicating what Qualifying Actions were used to meet the Emission Reduction Requirement in 2018. The expected Qualifying Actions total 9.2 million tons of emission reductions by 2018. The Company's proposed Qualifying Actions clearly demonstrate that identified reductions can more than exceed the Required Emissions Reduction estimate of 5.3 million tons.

APPENDIX K: NCUC ORDERS

The NCUC issued three orders since the filing of the 2011 Duke Energy Carolinas IRP that require Duke Energy Carolinas to specifically address new requirements in the 2012 IRP. An outline of the three orders and specific requirements are shown below.

1. Pursuant to its October 26, 2011 *Order Approving 2010 Biennial Integrated Resource Plans and 2010 REPS Compliance Plans*, the NCUC set forth new requirements listed below:

a) Duke Energy Carolinas and PEC should each prepare a comprehensive reserve margin requirements study and include the results of such study as part of their 2012 biennial IRPs.

A discussion of the comprehensive reserve margin study that Duke Energy Carolinas performed is found in Chapter 8 on page 85.

b) Each IOU and EMC should investigate the value of activating DSM resources during times of high system load as a means of achieving lower fuel costs by not having to dispatch peaking units with their associated higher fuel costs if it is less expensive to activate DSM resources.

A detailed discussion of this order is discussed below:

Dispatching DSM Resources for Fuel Savings

In Docket No. E-100, Sub 128, issued October 26, 2011, the NCUC order addressed the topic of dispatching DSM resources to capture fuel savings, stating, "each IOU and EMC should investigate the value of activating DSM resources during times of high system load as a means of achieving lower fuel costs by not having to dispatch peaking units with their associated higher fuel costs if it is less expensive to activate DSM resources. This issue should be addressed as a specific item in their 2012 biennial IRP reports."

Duke Energy Carolinas will address the Commission's requirement in 4 categories as listed below.

A. Duke Energy Carolinas Current DSM Programs Available to Capture Fuel Savings

Duke Energy Carolinas administers and implements a portfolio of DSM resources. Several of these DSM resources are specifically designed for use only during system emergency conditions, while others may be used as an economic resource. Resources utilized during system emergency conditions, programs such as Interruptible Service (IS), and PowerShare® Mandatory programs are dispatched by the Duke Energy Carolinas System Operations Center with an emphasis on system reliability. When implemented, these programs may capture fuel savings during these emergency implementations but cannot be dispatched in the absence of emergency conditions (i.e. economically) unless changes are made to the programs.

In contrast, Duke Energy Carolinas primarily implements the Power Manager® DSM resource for economic use and captures fuel savings when the power supply from generation options results in a relatively high marginal price. Utilizing DSM resources economically only on high marginal cost days maintains the number of activations at a reasonable level, and thus retains customer participation in these programs.

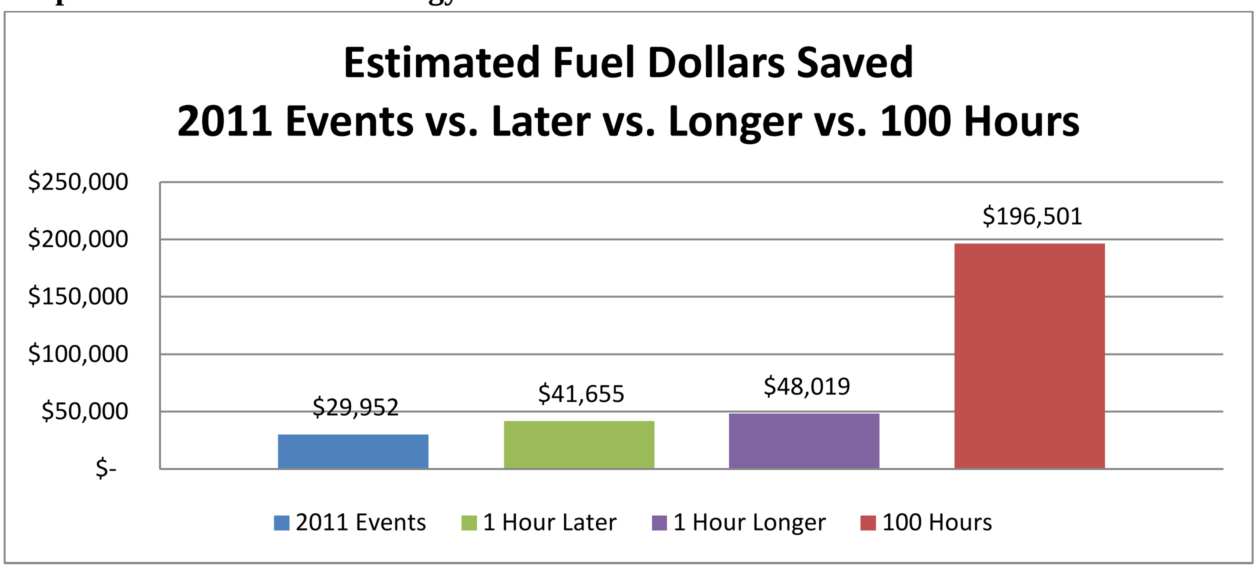
This discussion will concentrate on the Power Manager® program since it is the program with the most potential for capturing fuel savings at this time. There was no participation in PowerShare® CallOption in 2011 and the participation in the PowerShare® Voluntary program produced relatively small load reduction amounts (i.e., average load reduction during 2011 event hours of 4.4 MW). Therefore, the evaluation focused on the Power Manager® program.

B. Discussion of Capacity and Energy Value from DSM Resources

DSM resources can provide both avoided capacity cost benefits and avoided energy cost benefits. The capability to use Power Manager® for economic implementation was provided in Duke Energy Carolinas' filings in Docket No. E-7, Sub 831. The NCUC approved Power Manager® in its Order in the docket dated February 26, 2009.

With the utilization of actual load information from the summer of 2011, Duke Energy Carolinas explores the value of using the Power Manager® program to capture fuel savings. As exhibited on Graph K-1, slightly more avoided energy cost could be captured by having events either 1 hour later in the day and/or by extending the events for an additional hour. Assuming Duke Energy Carolinas would know which days were the highest price days to implement economic events throughout the summer, Scenario 4 shows that economic cycling of customers across 35 days for 100 hours produces greater avoided energy costs.

Graph K.1: 2011 Avoided Energy Cost Scenarios



Assuming these fuel saving were achieved over a 15 year period, the NPV of potential fuel savings are shown in Table K-1 below. The NPVs incorporates the rebound impacts of AC units using more energy after event hours than they would have used during the same hours had the event not occurred. The value captures price differentials between on-peak hours and off-peak hours. The energy values and corresponding fuel savings are very small when compared to the NPV of Avoided Capacity Costs equal to approximately $337 Million over a 15 year period for the Power Manager® program.

Table K.1

Avoided Energy Cost Scenario	2011 Scenario Avoided Energy Cost Results	15-year NPV Scenario Avoided Energy Cost
2011 Events	$29,952	$284,820
1 Hour Later	$41,655	$396,107
1 Hour Longer	$48,019	$456,621
100 Hours	$196,501	$1,868,575

C. Customer Perceptions and Behaviors Regarding DSM Resources

To address DSM resource implementation from the participant's perspective, Duke Energy Carolinas has gathered data from three sources to investigate customer reaction to increased program implementation, including a measure of their behavioral response (i.e., their decision to continue or terminate their participation in the DSM program).

1. Secondary Research Through E-Source: E-Source, an energy industry consulting firm, concluded that there is no universal limit to how frequently DR programs can be activated before participants become dissatisfied. The primary message Duke Energy Carolinas takes from the E-Source response is that participants should be engaged and "trained" on how the program works and the expectations of program implementation. This will allow customers to make an informed decision about participating in demand response programs. Duke Energy Carolinas will also carefully manage the cost of additional communications and customer training to avoid expenses beyond the savings provided by economic event implementation.

2. Primary Research Study with Power Manager® Participants and Non-participants: 532 Power Manager® Participants and 700 Power Manager® non-participants responded to a survey. The primary objective of this study was to investigate how customers would respond if program implementation increased up to approximately 100 hours each summer. This study found that increasing the length of a DSM event caused participation to drop significantly more than increasing the number of DSM events over a shorter period of time. In addition, among existing participants, the study also found that participating customers are very concerned with the end time of an event. Therefore, using the DSM program to achieve more fuel savings may result in unwanted attrition unless carefully managed.

3. Perceptions of Customer Experience and Other Program Comments from Duke Energy Carolinas DSM Program Managers
    a. PowerShare® Voluntary – Experience shows that event participation is low unless participant perception is that the system is stressed and an emergency could be pending. It is assumed that the large commercial and industrial customer participants are cognizant of the differential costs of curtailment versus the commitment to produce or serve their customers. Those costs or profits, are likely greater than the incentives possible through DSM avoided energy incentives. Most load reduction from this program is captured during emergency and close-to-emergency events.
    b. PowerShare® CallOption – For the summer of 2011, there were no participants in any of the program options offered as the program currently suffers from a relatively poor position in the Duke Energy Carolinas portfolio of DSM programs.
    c. Power Manager®® – As noted above, Duke Energy Carolinas converted the program from an emergency-only program to the Power Manager® program that allows for both economic and emergency implementation. This allows the capture of some of the additional benefit of avoided energy costs and provides increased operational flexibility. Prior to the summer of 2012, it was uncertain if a transition from an economic cycling event to an emergency full-shed event would function properly. During that time, on days when emergency events were considered possible, a Power Manager® economic cycling event was not implemented. The System Operations Center no longer requires that economic implementation be withheld now that upgraded systems will reliably transition from an economic event to an emergency event, if needed.

D. Duke Energy Carolinas' Current and Recommended DSM Implementation Process

Duke Energy Carolinas has established a portfolio of DSM programs to allow customers to select their level of involvement with demand response programs. Duke Energy Carolinas frequently communicates with customers about their program choices. Customers also benefit from savings through economic implementation of the programs. In addition, several programs are under consideration to provide customers more options and more active involvement with economic implementation of DSM resources in the future. Some of these are:

- Considering new programs such as energy management programs, electric vehicle demand response, demand response ready appliances, and a high involvement PS CallOption offering.

- Aligning of PowerShare® program incentives with the level of involvement selected by the customer
- Continuing efforts to replace Power Manager® devices with new functioning devices

Conclusion: Based on the research analyzed for the Power Manager® program, an increased number of short duration events ending early in the evening (i.e. 5 or 6 pm) can be tolerated by customers with little impact on customer satisfaction and program defection. However, given the large disparity between avoided capacity cost benefits and avoided energy cost benefits, the increased implementation strategy must be implemented slowly in order to monitor customer perception and closely track program enrollment levels. This new bias towards implementation can start as early as the summer of 2013. Therefore, Duke Energy Carolinas plans to continue its current economic event implementation process with a slightly increased bias toward implementation.

c) Each electric utility should use appropriately updated DSM/EE market potential studies.

A discussion of use of the Company's 2011 DSM/EE Market Potential study is found in Appendix A on page 103.

2) Pursuant to its May 30, 2012 *Order Approving 2011 Annual Updates to the 2010 Biennial Integrated Resource Plan and 2011 REPS Compliance Plans*, the NCUC set forth new requirements listed below:

a. Each IOU shall include a discussion of variance of 10% or more in projected Energy Efficiency savings from one IRP report to the next.

The projected total annual MWh load reductions associated with EE programs included in the base case for this 2012 IRP are more than 10% higher than those included in the 2011 IRP base case, primarily due to updated expectations of the performance of the EE programs beyond the initial 5 year planning period. The projected base case for this 2012 IRP reaches approximately the same total cumulative achievements, including actual achievements since 2009, by 2023 that were projected to be achieved by 2031 in the 2011 IRP.

b. Each IOU shall include a discussion of the status of market potential studies or updates in their 2012 and future IRPs.

In 2011, Duke Energy commissioned an independent Market Potential Study for both the North Carolina and South Carolina service territories. This study was prepared by Forefront Economics Inc. and was completed in December of 2011. The results of this Market Potential Study were incorporated into the Energy Efficiency forecasts included in this IRP.

3) Pursuant to its April 11, 2012 *Order Amending Commission Rule R8-60 and Adopting Commission Rule R8-60.1 in the Matter of Integrated Resource Planning in North Carolina addressing Smart Grid Technology Plans*, the NCUC set forth the requirements listed below.

a. Smart Grid Impacts – Each utility shall provide information regarding the impacts of its smart grid deployment plan on the overall IRP.

b. The Smart Grid Technology Plan – By July 1, 2013 and every two years thereafter, each utility subject to Rule R8-60 shall file with the Commission its smart grid technology plan. Significant amendments or revisions to a smart grid technology plan shall be reported to the commission in each year in which the biennial smart grid technology plan is not required to be filed.

A discussion of the Smart Grid Impacts and the Smart Grid Technology Plan is discussed on page 41 in Chapter 5.

APPENDIX L: CROSS-REFERENCE OF IRP REQUIREMENTS

The following table cross-references IRP regulatory requirements for North Carolina and South Carolina, and identifies where those requirements are discussed in the IRP.

Requirement	Location	Reference	Updated
15-year Forecast of Load, Capacity and Reserves	Ch 8, Table 8.A	NC R8-60 (c) 1	Yes
Comprehensive analysis of all resource options	Ch 4, 5 & 8, App A	NC R8-60 (c) 2	Yes
Assessment of Purchased Power	Ch 5, Sec D	NC R8-60 (d)	Yes
Assessment of Alternative Supply-Side Energy Resources	Ch 5, Sec B	NC R8-60 (e)	Yes
Assessment of Demand-Side Management	Ch 4, App D	NC R8-60 (f)	Yes
Evaluation of Resource Options	Ch 8, App A & C	NC R8-60 (g)	Yes
Short-Term Action Plan	Executive Summary	NC R8-60 (h) 3	Yes
REPS Compliance Plan	Filed Concurrently	NC R8-60 (h) 4	Yes
Forecasts of Load, Supply-Side Resources, and Demand-Side Resources			
* 10-year History of Customers and Energy Sales	Ch 3 & App B	NC R8-60 (i) 1(i)	Yes
* 15-year Forecast w & w/o Energy Efficiency	Ch 3 & App B	NC R8-60 (i) 1(ii)	Yes
* Description of Supply-Side Resources	Ch 5 & App C	NC R8-60 (i) 1(iii)	Yes
Generating Facilities			
* Existing Generation	Ch 5, Sec A	NC R8-60 (i) 2(i)	Yes
* Planned Generation	Ch 8 & App A	NC R8-60 (i) 2(ii)	Yes
* Non Utility Generation	Ch 5, Sec D	NC R8-60 (i) 2(iii)	Yes
Reserve Margins	Ch 8, LCR Notes	NC R8-60 (i) 3	Yes
Wholesale Contracts for the Purchase and Sale of Power			
* Wholesale Purchased Power Contracts	Ch 5, Sec D	NC R8-60 (i) 4(i)	Yes
* Request for Proposal	Ch 5, Sec D	NC R8-60 (i) 4(ii)	Yes
* Wholesale Power Sales Contracts	Ch 3 & App I	NC R8-60 (i) 4(iii)	Yes
Transmission Facilities	Ch 7 & App F	NC R8-60 (i) 5	Yes
Energy Efficiency and Demand-Side Management			
* Existing Programs	Ch 4 & App D	NC R8-60 (i) 6(i)	Yes
* Future Programs	Ch 4	NC R8-60 (i) 6(ii)	Yes
* Rejected Programs	Ch 4	NC R8-60 (i) 4(iii)	Yes
* Consumer Education Programs	Ch 4	NC R8-60 (i) 4(iv)	Yes
Assessment of Alternative Supply-Side Energy Resources			
* Current and Future Alternative Supply-Side Resources	Ch 5, Sec C & App C	NC R8-60 (i) 7(i)	Yes
* Rejected Alternative Supply-Side Resources	Ch 5, Sec C & App C	NC R8-60 (i) 7(ii)	Yes
Evaluation of Resource Options (Quantitative Analysis)	App A	NC R8-60 (i) 8	Yes
Levelized Bus-bar Costs	App C	NC R8-60 (i) 9	Yes
Smart Grid Impacts	Foreward & Ch 4	NC R8-60 (i) 10	Yes
Legislative and Regulatory Issues	Ch 6		Yes
Greenhouse Gas Reduction Compliance Plan	App J		Yes
Other Information (Economic Development)	App G		Yes